Natural Gas Market Assessment

Long-Term Canadian Natural Gas Contracts

NATIONAL ENERGY BOARD

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Foreword

This *Natural Gas Market Assessment: Long-Term Canadian Natural Gas Contracts* has been undertaken as part of the National Energy Board's ongoing monitoring of the Canadian natural gas market. The Board monitors the Canadian natural gas market to be alert to any difficulties for Canadians in adjusting to changes in natural gas supply and demand.

This monitoring includes the Board's periodic report: *Canadian Energy Supply and Demand* which examines the long-term prospects for Canadian supply of all major energy commodities, including electricity, oil and natural gas and their by-products, and the demand for Canadian energy in Canada and abroad.

As a second part of its ongoing monitoring, the Board analyses natural gas supply, demand and prices and periodically publishes reports on its findings, as it announced in a decision dated July 1987, in which the Board adopted a "Market-Based Procedure" to ensure that natural gas licensed for export is surplus to reasonably foreseeable Canadian requirements. These *Natural Gas Market Assessment* reports are focused entirely and in greater detail on natural gas markets and provide a short-term analysis. Thus they differ in their focus and in the period covered by the analysis from the *Canadian Energy Supply and Demand*, which, as explained above, examines all energy forms over the long term.

Previous *Natural Gas Market Assessment* reports published in 1988 and 1989 provided a comprehensive review of the overall structure and functioning of the natural gas market. The current *Natural Gas Market Assessment: Long-Term Canadian Natural Gas Contracts* provides a comprehensive descriptive analysis of the changes which have occurred and the developing trends in the long-term Canadian contracts governing the sale of western Canadian gas into the domestic and export markets from 1985 to 1991. The report is not about actual gas flows, past or present, but about the contractual arrangements which underpin such gas flows. The report is limited to domestic and export contracts for Canadian gas and this does not include imported gas under contract.

The report is focused on a specific part of the structure and functioning of the natural gas market: long-term Canadian natural gas contracts. This approach, although narrower in scope, enables the Board to focus on specific aspects of natural gas supply, demand and prices with the advantage of publishing more timely assessments of the various aspects of the structure and functioning of the natural gas market.

This report was prepared by Peter Milne & Associates Inc. in association with Board Staff. While this study is intended to be a factual study, any opinions expressed are those of Peter Milne & Associates Inc. and not necessarily those of the National Energy Board.

Inquiries on this report may be made by telephoning the Board's Information Services at (403) 299-2713.

Copies of this report or previous Board reports are available by contacting the Board at the address or telephone number provided on the back of the title page.

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Chapter 1
Introduction

The Canadian natural gas industry is made up of thousands of natural gas wells, hundreds of gas processing plants and an extensive network of gas gathering, transmission and distribution systems totalling thousands of kilometres. Since the 1950's, a large part of the investment in this infrastructure has been supported by long-term gas contracts between buyers and sellers.

In late 1985, the federal/provincial Agreement on Natural Gas Markets and Prices deregulated Canadian natural gas prices. At about the same time, the United States (U.S.) government and regulators began to deregulate the U.S. gas industry. Governments and regulators on both sides of the border implemented several measures to support the shift from regulated prices to market determined prices. Since the mid-1980's, the North American gas industry has become highly competitive and market oriented and, as a result, there have been major changes to the long-term contracting practices of buyers and sellers.

The purpose of this report is to analyze the changes that have occurred in long-term contracts governing the sale of western Canadian gas into domestic and export markets and to identify the important trends in contracting practices that have emerged since deregulation. The report focuses on the changes in the structure of long-term contracts, as well as the important changes that have occurred in the detailed terms and conditions of long-term agreements.

The analysis is based on a data base of more than 165 domestic and export contracts totalling more than 198.9 $10^6 m^3$/day (approximately 7,000 MMcfd) maintained by Peter J. Milne & Associates Inc. (See Appendix A for a complete listing of contracts surveyed.) The contracts included in the survey represent the first arm's length or primary sale[1] between a party representing producer interests (eg., a producer/marketer or supply aggregator) and a party representing consumer interests (eg., an end-user or demand aggregator). Contracts between producers and supply aggregators or between demand aggregators and end-users are not included in the survey.

Most of the contracts in the survey can be found in the public domain and are filed with the National Energy Board (NEB) or provincial regulatory boards. The individual contracts between the major British Columbia local distribution company, BC Gas Inc., and its suppliers (17 contracts), Canadian Western Natural Gas Company Limited/Northwestern Utilities Limited (CWNG/NUL), the major Alberta distribution company, and its suppliers (368 contracts) and Saskatchewan Energy and its suppliers (109 contracts) are not in the public domain. However, in many cases the contracts between each of these local distribution companies (LDCs) and their suppliers are relatively standard and a description of typical contract terms and conditions is included in the survey.

---

[1] A primary contract is defined as the first arm's-length agreement between a seller or seller's agent and the first buyer as an end-user or the end-user's agent.
For example:

Producer→WGML→Consumers Gas→end-user
Producer→Cogen's Agent→Cogen Plant
Producer→ProGas→ANE→Boston Gas
Producer (Shell)→Salmon Resources→C.E.T.I.

Table 1 - 1
Survey Summary

MARKET REGION	NO. OF CONTRACTS	CONTRACT VOLUMES	
		$10^3m^3/d$	MMcfd
BRITISH COLUMBIA	17	13.0	458.0
ALBERTA AND SASK.	3	20.0	705.0
CENTRAL CANADA	31	33.2	1 173.2
TOTAL DOMESTIC	51	66.2	2 336.2
US NORTHEAST	63	48.7	1 719.3
US MIDWEST	36	41.5	1 466.4
CALIFORNIA	6	34.7	1 223.3
US PACIFIC NORTHWEST	13	7.8	276.4
TOTAL EXPORT	118	132.7	4 685.4
TOTAL MARKET	169	198.9	7 021.6

Note: The total number of CWNG/NUL and Sask Energy contracts is 477.

The survey includes all export contracts that have been filed with the NEB as of December 1991 (See Table 1-1). This includes contracts which have been filed in support of an export licence application, but which has not yet been heard or approved by the Board. It is important to include all contracts in the survey, even if they are not yet approved, to identify the most recent trends in contracting practices. However, the inclusion of these contracts in the analysis in no way prejudices the Board's decision with respect to the application.

The primary focus of the report is on contracts and contract terms and conditions. It does not focus on contract performance such as actual gas flows or prices. In many cases, gas has not yet begun to flow. Either the parties are waiting for pipeline capacity to be installed or in other instances all the necessary regulatory approvals have not been received.[2] (Unless otherwise noted, all references to volumes in this study are in terms of Daily Contract Quantities (DCQ).)

For the purpose of this analysis, a long-term contract is defined as one which has an initial term greater than five years. The shortest contract term in the survey is six years. Contracts that are long-term but allow for termination prior to the initial term (i.e., for example, parties are unable

[2] In cases where the contract volumes increase over the first two or three years of the agreement, the full contract volumes have been used.

to agree on a price for a forthcoming pricing period) are included in the survey on the basis that the objective of the contract is to establish a long-term contractual relationship. Also, contracts that were initially long-term but only have a few years remaining are included in the survey.

Sellers have been categorized into three groups: traditional supply aggregators, i.e., aggregators who were active prior to deregulation (eg., ProGas Limited (Progas), TransCanada PipeLines Limited (TransCanada) and its marketing agent, Western Gas Marketing Limited (WGML)); new supply aggregators (eg., Northridge Petroleum Marketing, Inc. (Northridge) and Unigas Corporation (Unigas)); and producer/marketers (eg., Northstar Energy Corporation (Northstar), Poco Petroleums Ltd. (Poco) and Shell Canada Limited (Shell).) who sell directly to end-users and demand aggregators. Many producers/marketers not only market their own gas supply but also market the gas of others.

Buyers have also been divided into three groups: local distribution companies (LDCs); U.S. interstate pipelines; and cogeneration and electric utilities. Electric utilities have not yet become a major purchasing group and the few contracts negotiated to date (eg., New England Power Company (NEPC) and Southern California Edison Company (SoCal Edison) have been included with the cogeneration contracts.

To enable geographic trends in contracts to be identified, the market for western Canadian gas is divided into seven regions: British Columbia; Alberta and Saskatchewan; central Canada, including Manitoba; the U.S. Northeast; the U.S. Midwest; California; and the U.S. Pacific Northwest, including Idaho and Nevada (Figure 1-1).

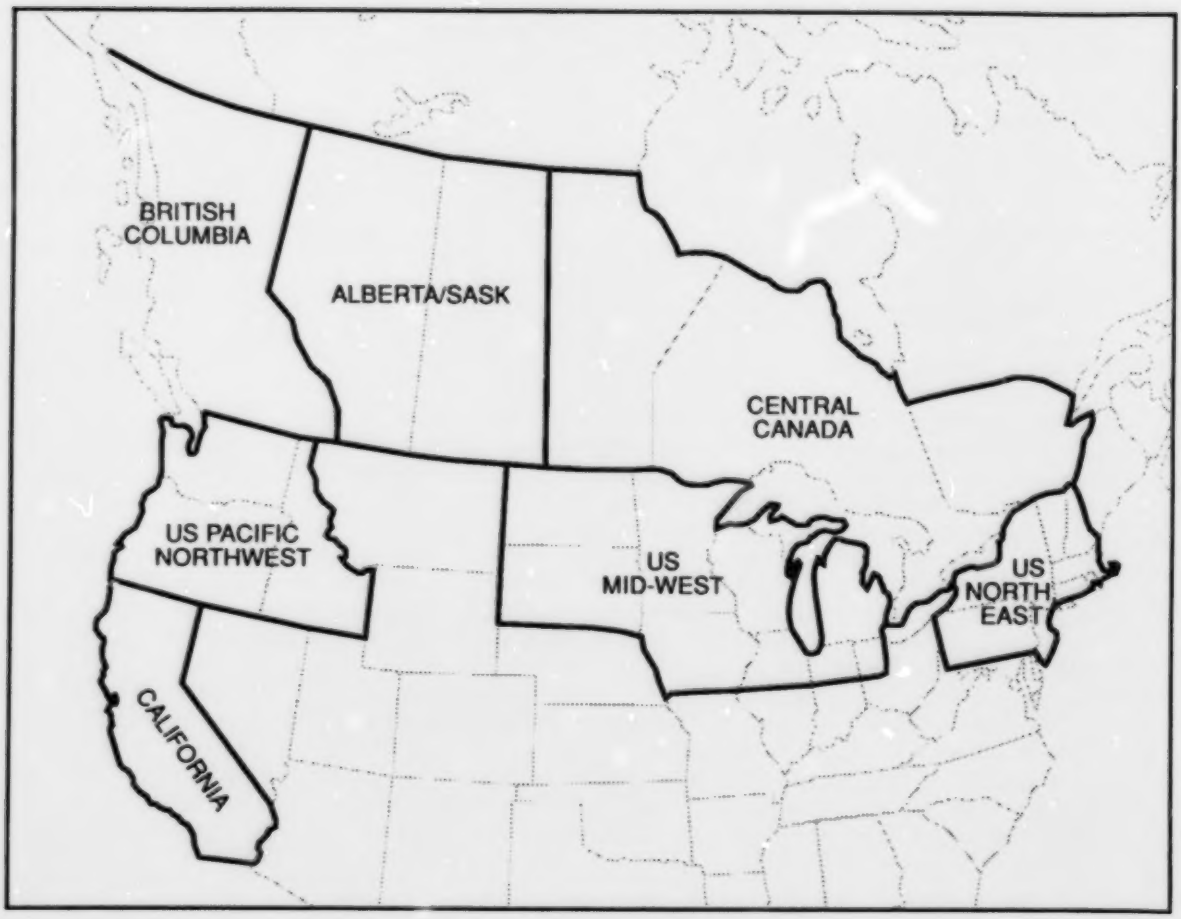
Chapter 2 of the report analyzes the change in the structure of long-term contracts and transportation arrangements between the buyer and the seller since natural gas deregulation. It documents the trend towards shorter-term and smaller volume contracts as well as the changing importance of long-term contracts compared to short-term agreements.

Chapter 3 identifies trends in the detailed terms and conditions of natural gas agreements. It analyzes the use of different mechanisms to secure the buyer's contractual obligations to purchase gas and the seller's commitments to deliver gas, and focuses on the balance between the buyer's and seller's obligations. Chapter 3 also considers the different pricing practices and pricing indices used by contracting parties.

Chapter 4 summarizes the key conclusions and identifies the important differences between domestic and export contracting patterns.

Figure 1 - 1

Major Market Regions for Canadian Gas



Chapter 2

The Changing Structure Of Long-Term Canadian Natural Gas Contracts

The sale and transportation of natural gas from the wellhead to the point of use or burner tip are typically arranged through a series of contractual, transportation and administrative arrangements between buyers and sellers, often including agents and corporate affiliates. During the fifteen years prior to the regulation of gas prices in 1975 and throughout the decade of price regulation, the contracting patterns of buyers and sellers remained essentially unchanged. However, beginning with natural gas price deregulation in Canada and the U.S. in the mid 1980's, important new trends in contracting and transportation arrangements between buyers and sellers have evolved.

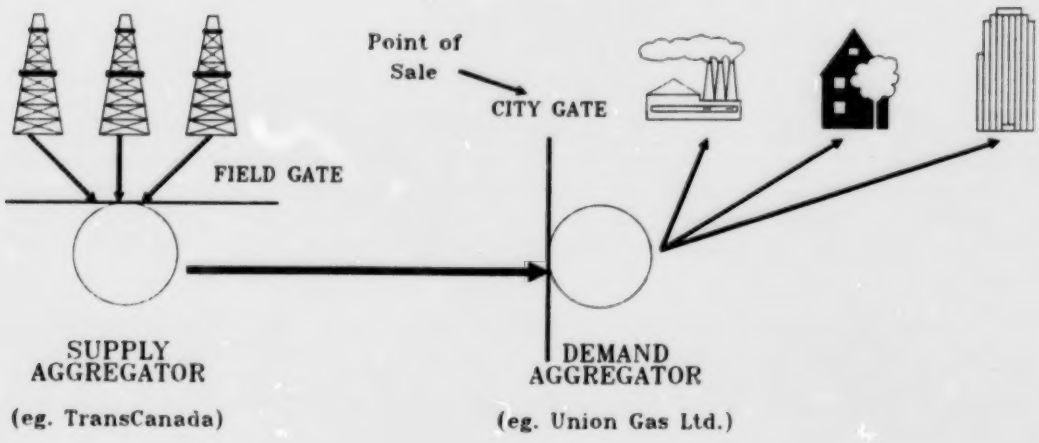
The purpose of this Chapter is to identify the structural changes in long-term contracting practices of the various types of buyers and sellers serving different market regions that have occurred since deregulation. Some of the fundamental changes identified are the trend towards shorter term, smaller contracts and the growth of short-term markets. Changes in transportation arrangements are also examined.

2.1 Contract Structures Prior to Deregulation

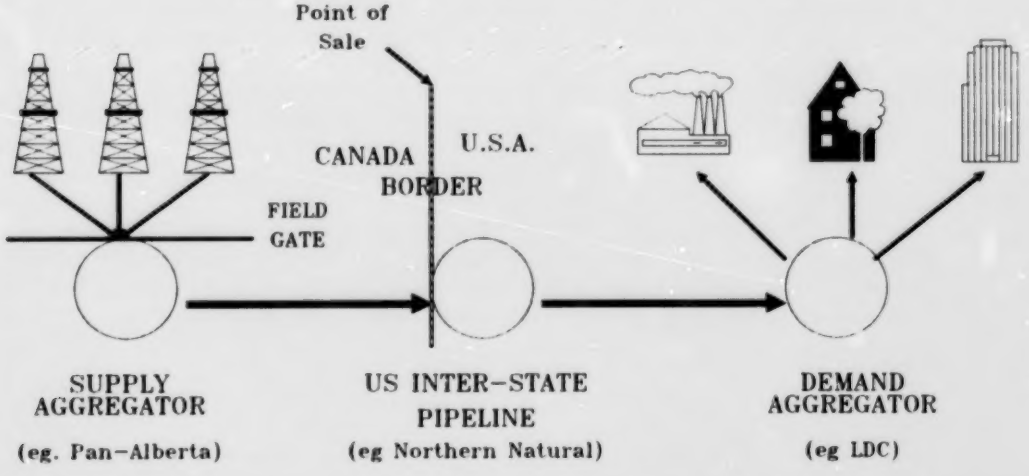
The standard contracting arrangements for western Canadian gas between the late 1950's and early 1980's was developed by pipeline companies such as TransCanada and Westcoast Energy Inc. (Westcoast), formerly Westcoast Transmission Company Limited. These companies purchased large volumes of gas directly from producers at the fieldgate or wellhead under long-term agreements (usually 20 to 25 year terms) to ensure that there would be adequate volumes of gas supply under their control to maintain pipeline throughput and to fulfil their contractual obligations with buyers to deliver gas. The pipeline companies sold gas from their supply pools at the various delivery points on their systems to demand aggregators such as Canadian LDCs and U.S. interstate pipelines - which in turn supplied U.S. LDCs. The supply aggregators (eg., Westcoast and TransCanada) controlled the necessary pipeline capacity to transport gas through pipeline ownership, except within Alberta where the required capacity was contracted by the aggregators on NOVA Corporation of Alberta (formerly Alberta Gas Trunk Lines), which has always operated as a contract carrier.

Figure 2 - 1

Traditional Gas Contracting Domestic Arrangement



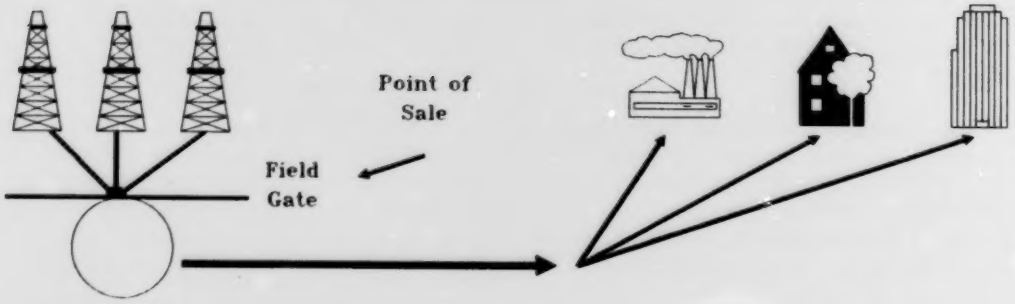
Traditional Gas Contracting Export Arrangement



Until 1985, when natural gas prices were deregulated, most western Canadian gas was sold under contractual arrangements similar to those depicted in Figure 2-1, except in Saskatchewan, Alberta and California (Figure 2-2). In these latter markets, the demand aggregators or LDCs also acted as supply aggregators and purchased their gas requirements either directly from producers or through affiliated companies.

Figure 2 - 2

Traditional Gas Contracting
Alberta, Saskatchewan and California



(Sask Power, A&S/PGT/PG&E, CWNG/NUL)

In the 1970's, new supply aggregators emerged, such as Pan-Alberta Gas Ltd. (Pan-Alberta) and ProGas, who operated on a similar basis as the earlier pipeline aggregators except that they controlled pipeline capacity through long-term contractual relationships with pipelines rather than through pipeline ownership.

Until 1985, western Canadian gas was sold to end-users in several different market regions almost exclusively through aggregators under a small number of large volume, long-term contracts. Outside of the Alberta market, very little gas was sold on a short-term basis and no gas was sold directly by producers and to end-users[3]. All gas sales were made through supply aggregators to demand aggregators, i.e., LDCs or U.S. interstate pipeline companies.

2.2 Contract Structures in the Post Deregulation Era

By late 1985, several initiatives had been taken in Canada and the U.S. to deregulate natural gas markets. In Canada, the governments of the gas producing provinces and the federal government negotiated the Western Accord (27 March 1985) and the Agreement on Natural Gas Markets and

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[3] In late 1984, Simplot Chemicals Ltd. in Manitoba executed the first direct sale of Alberta gas to an ex-Alberta market.

Prices (31 October 1985). One of the objectives of these Agreements was to enable new participants to enter the marketplace and to provide end-users and gas producers with greater flexibility and new alternatives under which to buy and sell natural gas.

The National Energy Board, in response to the intergovernmental agreements, from 1 November 1985 implemented several measures designed to assure new participants, including end-users, producers and marketers, non-discriminatory access to federally regulated pipelines.[4] In the U.S., the Federal Energy Regulatory Commission's (FERC) Order 500 (first issued in 1985 as Order 436) created incentives for U.S. pipelines to become "open access" carriers. This gave U.S. buyers, such as LDCs and industrial users, the option to purchase gas directly from producers or supply aggregators in Canada or the U.S. while being assured of pipeline capacity to transport the gas.

These changes created a tremendous increase in the demand for "unbundled" services (i.e. parties elected to contract for gas supply and transportation services). At the same time, the demands on traditional supply aggregators who typically offered "bundled" sales service that included both gas and transportation have been reduced. The changes also encouraged new participants to enter the market and, as a result, the number of buyers and sellers has increased dramatically. This has had an important impact on the structure of natural gas contracts as well as the terms and conditions of contracts.

The effects of deregulation have not been uniform across all market regions. The U.S. Northeast, in which there has been significant incremental growth for western Canadian gas since 1985 and thus creating opportunities for new market entrants, has exhibited the greatest change and, in many instances, has set the pattern for change in other market regions. The U.S. Midwest, where there has been a decline in the demand for gas under long-term contract and where many of the pre-1985 contracts continue to be in effect, has experienced fewer changes. The typical long-term contract structure between buyers and sellers in the Alberta/Saskatchewan market has remained essentially unchanged.

2.2.1 Central Canada

The structure of long-term contracts governing the sale of gas to the central Canadian market, including Manitoba, has changed dramatically. Until 1988, each of the major distribution companies in Quebec, Ontario and Manitoba purchased all its gas requirements from TransCanada at the city-gate or the point of interconnection between TransCanada and the distribution system.[5]

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[4] Since 1986, the National Energy Board has issued several decisions amending TransCanada, Foothills Pipelines Ltd. and Westcoast tariffs to ensure non-discriminatory access to firm and interruptible pipeline capacity. The Board's criteria for licensing long-term gas exports have been made more flexible; orders authorizing short-term exports are available from the Board on request; and amended criteria have been introduced for new pipeline facilities approvals. These changes have all been undertaken to facilitate the transition to a competitive marketplace.

[5] The only exceptions were two small contracts between Pan-Alberta, a supply aggregator, and Gaz Métropolitain inc. (GMi) negotiated in the early 1970's, and Société Quebecoise d'Initiatives Petrolieres (SOQUIP) and GMi negotiated in the early 1980's in which GMi purchased the gas at Empress, Alberta, the inlet to the TransCanada system.

Three major structural changes have occurred in the central Canadian market. First, 40 percent of the market today is served by gas purchased under long-term agreements, primarily by LDCs to serve the residential market, some of the commercial market and a few industrial accounts, (see Table 2-1), whereas in 1985, the market was served entirely by gas purchased under long-term contracts. Second, the LDCs now purchase all of their firm gas requirements at the Alberta/Saskatchewan border[6] from a diversified portfolio of suppliers, including the traditional supply aggregators, such as WGML (which was created in 1986, is the marketing arm of TransCanada) and from new market entrants, including direct purchases from producers/marketers (Figure 2-3).

Table 2 - 1
CENTRAL CANADIAN MARKET
SHORT-TERM vs LONG-TERM CONTRACTS
1991/92 Gas Contract Year

FRANCHISE AREA	CONTRACTS	LONG-TERM CONTRACT VOL		SHORT-TERM CONTRACT VOL		TOTAL		PERCENTAGE SHORT TERM	LONG TERM
		($10^3m^3/d$)	(MMcf/d)	($10^3m^3/d$)	(MMcf/d)	($10^3m^3/d$)	(MMcf/d)		
Gaz Métropolitain	GMi/WGML	2 181.3	77.0						
	GMi/Pan-Alberta	509.9	18.0						
	GMi/SOQUIP	368.3	13.0						
	Direct Purchases			12 521.2	442.0	15 580.7	550.0	80.4%	19.6%
	Total	3 059.5	108.0						
Consumers' Gas	Consumers/WGML	8 640.2	305.0						
	Consumers/Non-WGML	4 957.5	175.0						
	Direct Purchases			15,269.1	539.0	28 866.9	1 019.0	52.9%	47.1%
	Total	13 597.7	480.0						
Union Gas	Union/WGML	2 492.9	88.0						
	Union/Non-WGML	4 022.7	142.0						
	Direct Purchases			16 005.7	565.0	22 521.2	795.0	71.1%	28.9%
	Total	6 515.6	230.0						
Centra Ontario Gas	Centra/WGML	3 342.8	118.0						
	Direct Purchases			6 798.9	240.0	10 141.6	358.0	67.0%	33.0%
	Total	3 342.8	118.0						
Centra Manitoba	Centra/WGML	7 648.7	270.0						
	Direct Purchases			1 529.7	54.0	9 178.5	324.0	16.7%	83.3%
	Total	7 648.7	270.0						
TOTALS	LDC/WGML Contracts	24 305.9	858.0					28.2%	
	LDC/Non-WGML Contracts	9 858.4	348.0					11.4%	
	Direct Purchases			52 134.6	1 840.0			60.4%	
	TOTAL	34 164.3	1 206.0	52 134.6	1 840.0	86 289.0	3 046.0	60.4%	39.6%

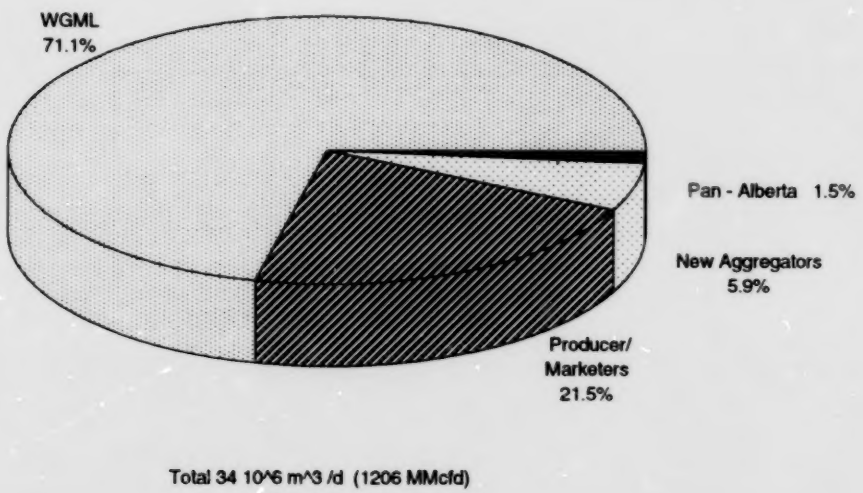
Notes: 1. Many commercial direct purchases in Quebec are backed by 5 to 10 year supply commitments.
2. Direct purchases in Manitoba are expected to expand rapidly as a result of recent changes implemented by the Manitoba Public Utilities Board.

[6] Union Gas Limited (Union Gas) purchases 425 10^3 m^3 per day (15 mmcfd) under a long term contract from Northridge at St. Clair, Ontario and 283 10^3m^3 per day (10 mmcfd) from Unigas at Oakville, Ontario.

Third, the LDCs hold long-term transportation contracts for most of the capacity on TransCanada required to transport gas to their franchises. Fourth, the gas contracted under short-term arrangements by commercial and industrial buyers is transported on TransCanada either directly by the buyers or their suppliers or indirectly through the LDC under buy/sell arrangements.

Figure 2 - 3

Central Canadian LDC Long - Term Supply Portfolio By Type of Suppliers, 1991

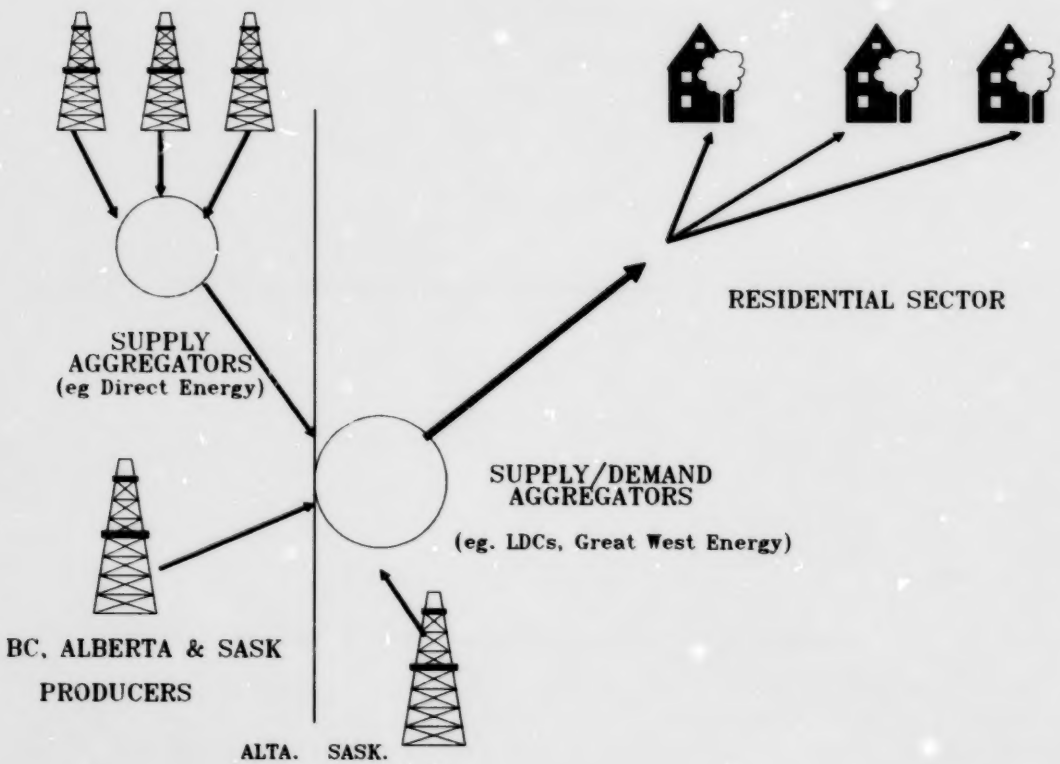


The LDCs have become supply aggregators in addition to their traditional role as demand aggregators. Figures 2-4 to 2-6 illustrate how the role of supply aggregators and the composition of LDC sales customers has changed in this market. The residential sector continues to rely largely on LDCs[7] for gas supply which the LDCs purchase under long-term agreements (Figure 2-4).

[7] Several new companies have recently entered the market as demand aggregators that are also serving the residential sector.

Figure 2 - 4

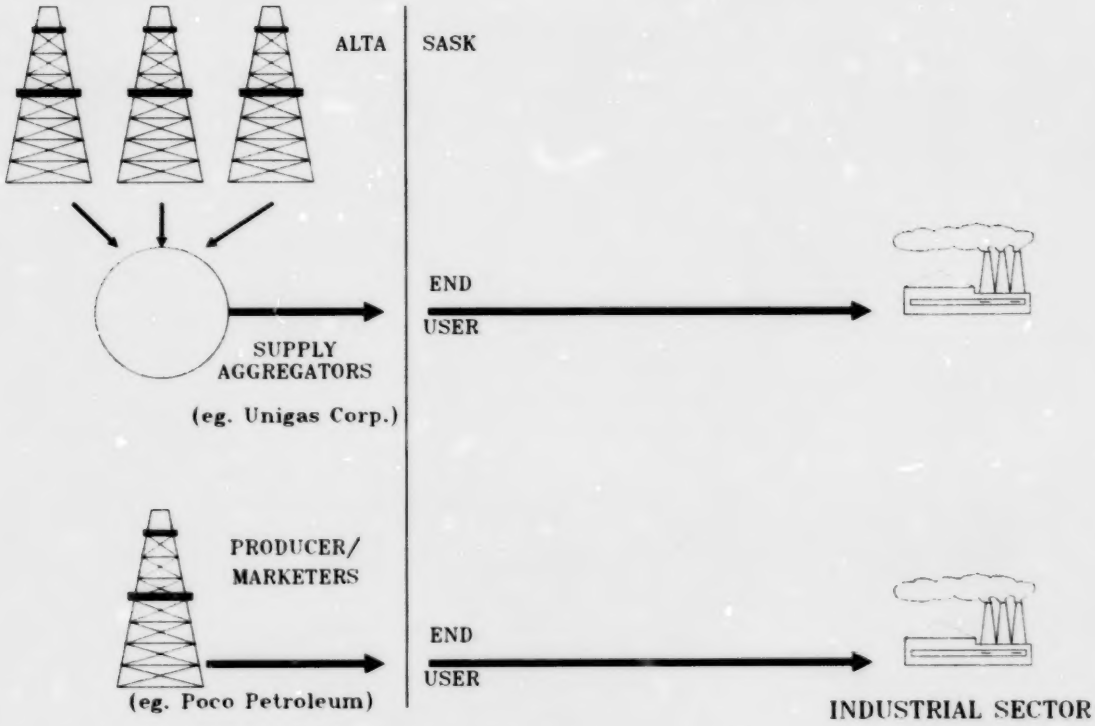
Post Deregulation Gas Contracting Arrangements
Central Canadian Residential Market



The central Canadian market has shifted towards a greater reliance on short-term contracts in the industrial and commercial sectors. These two market sectors are served directly by producer/marketers (eg., Poco and Shell), new aggregators (eg., Unigas), as well as the traditional supply aggregators (eg., WGML) (Figure 2-5 and Figure 2-6).

Figure 2 - 5

Post Deregulation Gas Contracting Arrangements
Direct Sales to the Industrial Sector

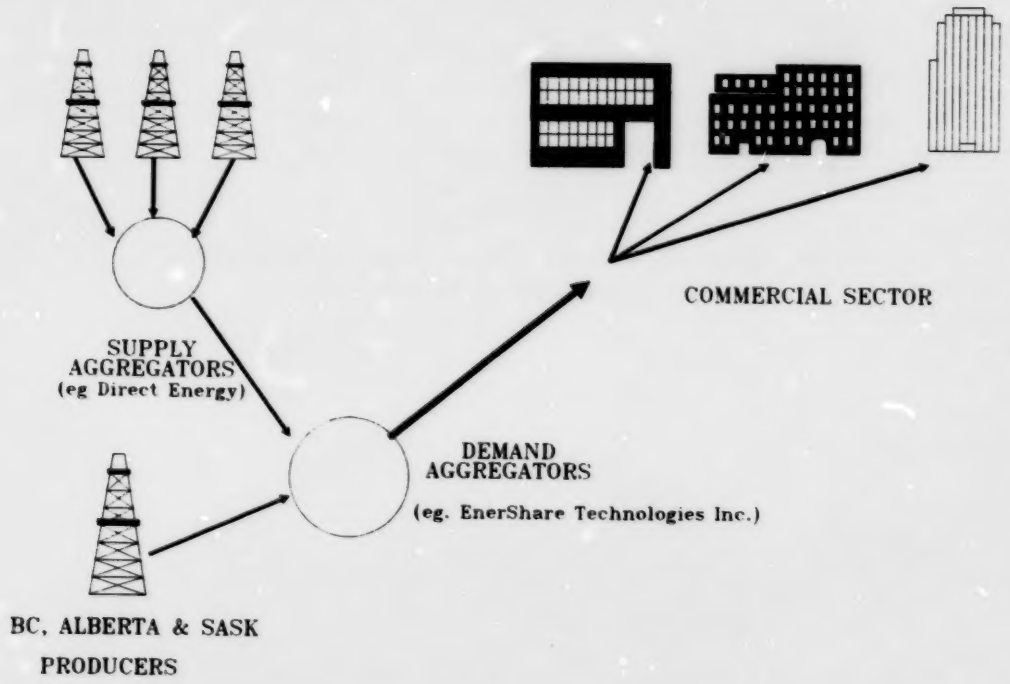


In the commercial and small industrial sector, demand aggregators who are independent of the LDCs have entered the market. These aggregators group together large numbers of buyers to facilitate direct purchases. Direct purchases have also been facilitated through "buy/sell" arrangements with LDCs which enable the distributors to continue to provide end-users with an efficient load balancing service.

Cogeneration is emerging as a new market sector in central Canada and most of the required gas is being purchased under long-term agreements. However, these contracts are not in the public domain and, therefore, are not available for this study.

Figure 2 - 6

Post Deregulation Gas Contracting Arrangements
Direct Sales to the Industrial Sector



2.2.2 Alberta and Saskatchewan

The Alberta and Saskatchewan market has changed little since natural gas deregulation. The largest LDCs which serve most of this market, CWNG and NUL and Sask Energy (formerly ProvGas and Saskatchewan Power Corporation), act as both demand and supply aggregators, purchasing most of their system gas requirements directly from a large number of producers at the field or city-gate under long-term contracts executed in the 1960's and early 1980's. Sask Energy and CWNG/NUL have approximately 19.8 10^6 m^3/day (700 MMcfd) contracted with producer/marketers under 477 contracts. CWNG/NUL also purchases relatively small volumes of gas from the traditional supply aggregators (Alberta and Southern Gas Co. Ltd. (A&S), Pan-Alberta, ProGas and WGML) under unique contracts which are tied to the terms of the aggregators' Alberta removal permits.

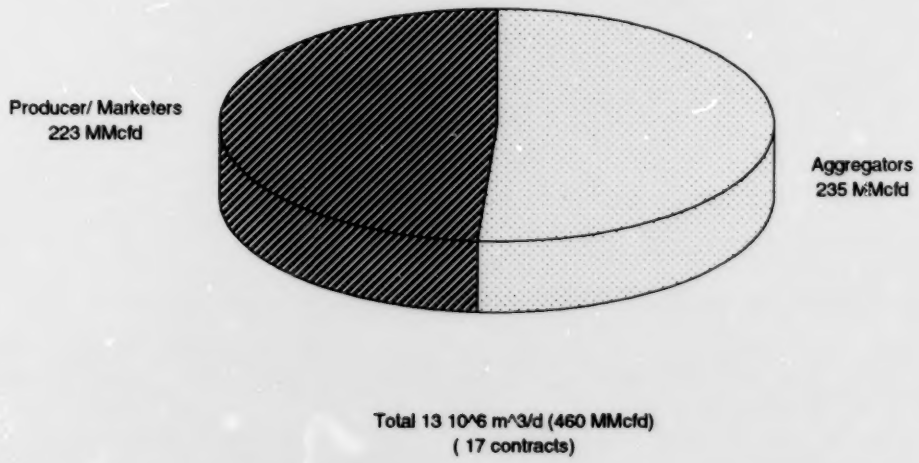
Many Alberta industrial users also purchase gas under long-term contracts (eg., Novacor Chemicals (Canada) Ltd. (shrinkage gas) and Syncrude Canada Ltd.). The terms and conditions of these contracts are not in the public domain and are not included in this survey. The contracts are generally direct between the buyer and producer/marketers, and transportation is arranged on a case by case basis.

2.2.3 British Columbia

Like the central Canadian market, the British Columbia (B.C.) market has been completely restructured. Until the end of the 1990/91 contract year, the major B.C. utilities (Inland Natural Gas Co. Ltd. and B.C. Hydro)[8] purchased their gas requirements from the provincial supply aggregator, British Columbia Petroleum Corporation (B.C.P.C.) which became CanWest Gas Supply Inc. (CanWest) in 1990. In late 1991, the major LDC, BC Gas Inc., became its own supply aggregator and has diversified its supply portfolio by contracting for its gas requirements from a range of suppliers, including CanWest and more than fifteen producer/marketers (Figure 2-7). BC Gas Inc. purchases gas from suppliers at different points, including the wellhead, Westcoast's No. 2 Compressor Station and the city gate.

Figure 2 - 7

BC Gas Inc. Long - Term Supply Portfolio
By Type of Suppliers, 1991



2.2.4 U.S. Northeast

The U.S. Northeast market for Canadian gas has seen dramatic changes since deregulation both in terms of its growth and in the emergence of a new market sector for natural gas, cogeneration.

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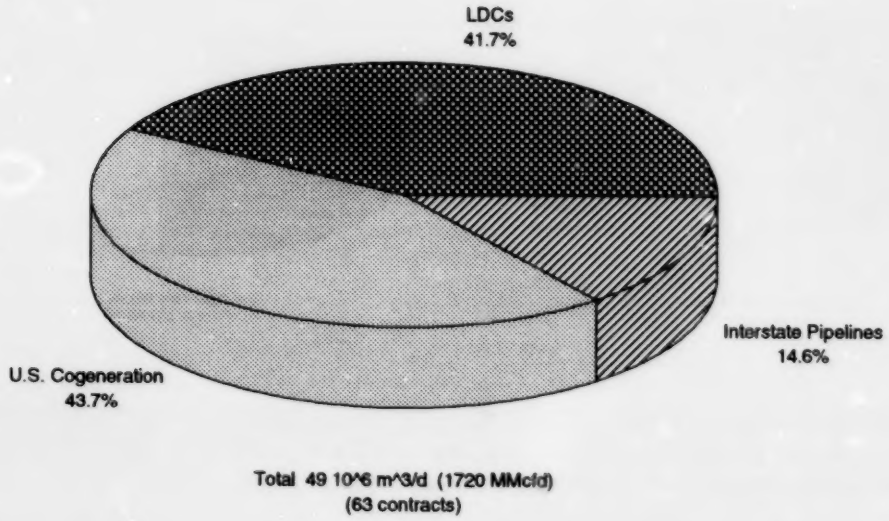
[8] In 1987, B.C. Hydro's gas distribution assets were purchased by Inland Gas, and the company was renamed BC Gas Inc.

Cogeneration has brought with it several innovative and important changes to long-term natural gas contracts.

In 1985, the US. Northeast was a market that held considerable potential for western Canadian gas but relatively few contracts to serve this market had been executed. Excluding the two small LDCs (St. Lawrence Gas Transmission Company and Vermont Gas Systems, Inc.) who have been served by Canadian gas since the 1960's, less than 10 10^6 m^3/day (350 MMcfd) of Alberta gas was contracted to this market in 1985. By the end of 1991, more than 48 10^6 m^3/day (1,700 MMcfd) of British Columbia, Alberta and Saskatchewan gas has been contracted to the U.S. Northeast. (Figure 2-8)

Figure 2 - 8

U.S. Northeast
Long - Term Canadian Gas Contracted Volumes
By Type of Purchasers, 1991



Since 1985, 43 percent of new sales have been to U.S. LDCs, either directly or through consortiums of LDC purchasers (eg., Alberta Northeast Gas Limited (ANE)), and 57 percent have been to cogeneration plants. There have been no new contracts with U.S. interstate pipelines serving this market.

In addition to traditional marketers, such as WGML and ProGas, who have been active in this market since the early 1980's, several new supply aggregators and producer/marketers have entered the marketplace.

U.S. Northeast LDCs have contracted to purchase Canadian gas from supply aggregators and, in a small number of cases, from producer/marketers at the Canada/U.S. border under traditional contract arrangements where the supply aggregator or the producer/marketer holds the pipeline capacity to the export point. The structure of cogeneration contracts is considerably more varied and in most cases quite different from LDC contracts with respect to point of purchase and transportation arrangements.

Figure 2 - 9

Long - Term Canadian Gas Contracted Volumes To U.S. Northeast Cogens By Type of Suppliers

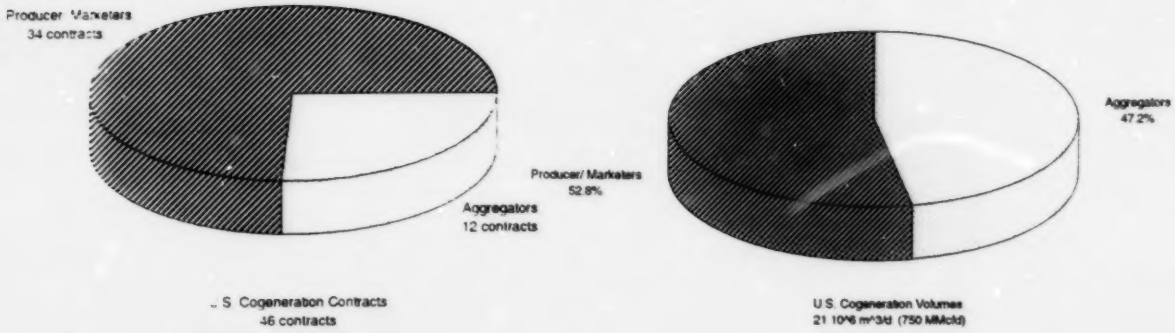


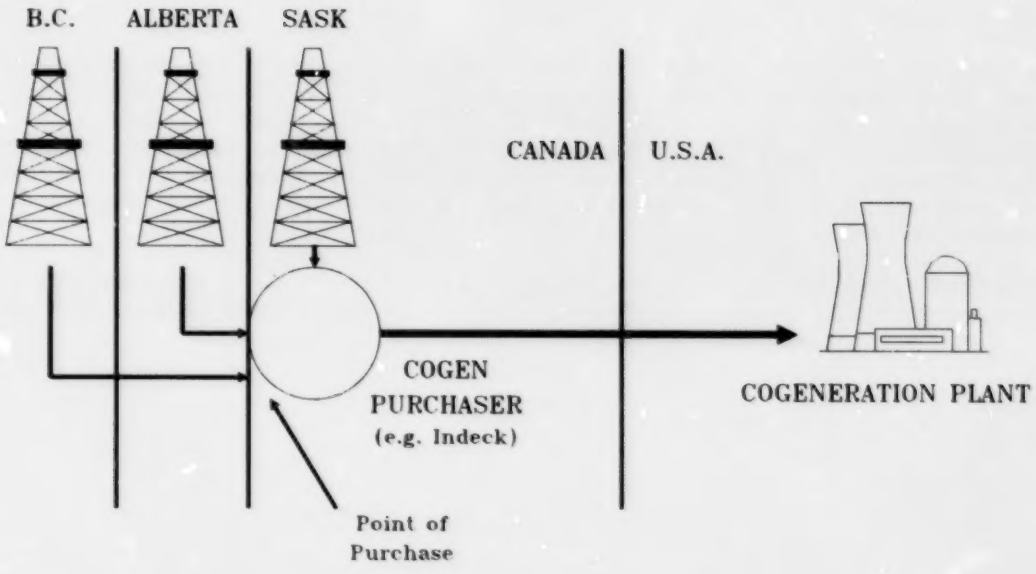
Figure 2-9 indicates that while traditional supply aggregators have been active in the cogeneration market, producer/marketers have sold the largest volume to this new sector, and the largest number of new contracts are between cogeneration plants and producer/marketers.

In most instances, the traditional supply aggregators have maintained their standard contracting framework for sales to the cogeneration sector. In these contracts the gas is sold to the cogeneration plant at the point of export (eg., Iroquois or Niagara Falls, Ontario) and the aggregator holds the required transportation capacity in Canada.

Many producer/marketers and cogeneration plant owners have used alternative contract structures. Often a cogeneration operator will act as its own supply aggregator, purchasing gas from one or more sellers at the inlet to the TransCanada pipeline system in either Alberta or Saskatchewan. The cogeneration plant or its agent will hold the required transportation capacity on TransCanada to the export point. (In certain cases, the cogeneration plant has assigned its TransCanada capacity to the producer/marketer to administer.)

Figure 2 - 10

Gas Contract Arrangements
U.S. Northeast Cogens



As of December 1991, 30 U.S. Northeast cogeneration contracts out of a total of 46 contracts use the structure illustrated in Figure 2-10.

2.2.5 U.S. Midwest

The U.S. Midwest has been the largest export market for Canadian gas since the late 1950's. Prior to 1985, it was characterized by a few large volume contracts between U.S. interstate pipelines and the traditional supply aggregators for sales at the export points, Monchy, Saskatchewan and Emerson, Manitoba. (See Figure 2-11.)

This market has been dramatically affected by the economic restructuring of the U.S. midwest economy that occurred during the 1980's and the changes in U.S. natural gas regulations. Since the mid 1980's, Canadian aggregators have taken steps to "unbundle" many of the existing contracts with interstate pipelines and contract directly with LDCs in the Midwest. However, the process has been slow, because of the complicated contractual arrangements between interstates, LDCs and supply aggregators, including outstanding take-or-pay obligations.

Since 1985, as the original long-term contracts expired, many U.S. midwest LDCs and interstate pipelines are renewing their purchase agreements directly with either the original supply aggregator or with several different suppliers.

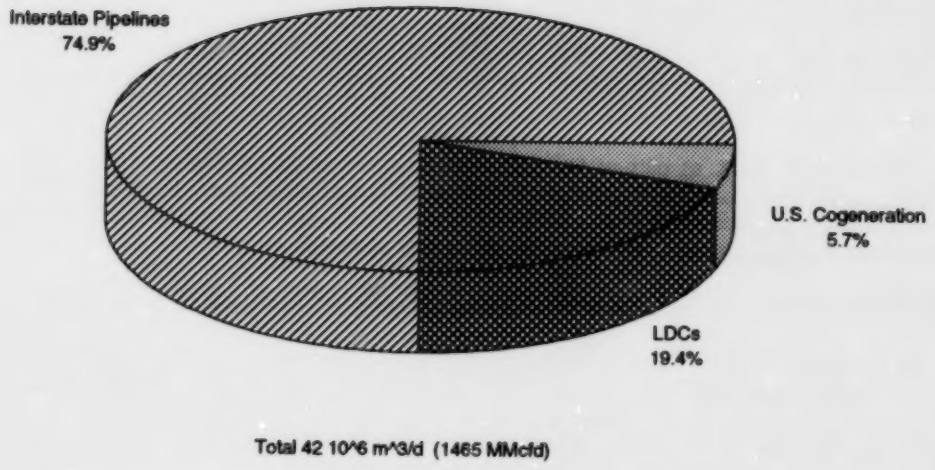
The total volume of gas contracted to the U.S. Midwest on a long-term basis has decreased in recent years. Figure 2-11 reveals that, unlike the U.S. Northeast, U.S. Midwest cogeneration is currently not a major market for Canadian gas and LDCs purchase less gas compared to interstate pipelines. Also, 80 percent of the gas contracted to the U.S. Midwest on a long-term basis is sold by the traditional supply aggregators, Pan-Alberta, ProGas and WGML.

Further, all of the gas sold to the U.S. Midwest is sold at the export point, with the exception of three recent contracts where the marketers, Pan-Alberta, WGML and Mobil Oil Canada (Mobil), hold capacity on the U.S. pipeline, Northern Border Pipeline, and will sell gas to the U.S. buyer (Northern Natural Gas Company) at Ventura, Iowa (the current terminus of the Northern Border pipeline system). These contracts represent the first time that the primary point of sale between the seller and the buyer for Canadian gas under long-term contract has been south of the Canada/U.S. border.

A second important exception is the recent agreement between Amoco Canada Petroleum Co. Ltd. (Amoco) and Northern States Power Company (NSP), a U.S. Midwest LDC, in which NSP will hold the TransCanada capacity from Empress, Alberta.

Figure 2 - 11

U.S. Midwest
Long - Term Canadian Gas Contracted Volumes
By Type of Purchasers



The principal explanation for the relatively static behaviour of the U.S. Midwest market compared to other regions is the lack of growth in demand for gas secured by long-term contract. This is largely due to the easy accessability to U.S. mid-continent and Gulf Coast spot gas through several pipelines. In addition, many of the current contracts have been in existence since the 1970's and are difficult to change. As these contracts expire, they are being replaced by new contracts, often directly between the seller and LDCs.

2.2.6 California

Until recently, natural gas deregulation has brought few changes to the structure of the long-term contracts serving California. The California market has been served largely by two traditional supply aggregators, A&S and Pan-Alberta, under two different contract structures.

The A&S/Pacific Gas Transmission Company (PGT) contract was one of the first long-term contract arrangements for western Canadian gas and it continues to be the largest single contract governing the sale of western Canadian gas. It is also unique in other important respects. A&S, unlike other supply aggregators, is a wholly-owned subsidiary of the buyer, Pacific Gas and Electric Company (PG&E), a large LDC serving northern California. PG&E serves as both a supply and demand aggregator, purchasing Alberta gas at the fieldgate (through its affiliate, A&S),

rather than at the export point, using a framework similar to Alberta LDCs and Saskatchewan Energy (Figure 2-2). A&S sells gas to PGT at the export point. PGT transports the gas to the northern California/Oregon border where it is sold to PG&E. Like A&S, PGT is a wholly-owned subsidiary of PG&E.[9]

The second contract to supply California is between Pan-Alberta and the Southern California Gas Company (SoCal), which is structured in the traditional export framework,[10] with the sale between the supply aggregator and the buyer occurring at the export point (Kingsgate, B.C.) (Figure 2-1).

In the spring of 1991, four new contracts were executed between SoCal Edison, a large electric utility, and three producer/marketers and a supply aggregator. The buyer, SoCal Edison, will purchase the gas in Canada at Coleman at the Alberta/B.C. border and will control the transportation capacity downstream from that point, rather than purchasing gas at Kingsgate, B.C., the export point.

Over the last few years, as part of the proposals to construct the Altamont Gas Transmission Company Limited pipeline and expand the PGT system to California, there have been several new contracts negotiated directly between California buyers and Canadian producer/marketers that have not yet been made public and are not included in this assessment.

2.2.7 U.S. Pacific Northwest (including Idaho and Nevada)

For many years, the U.S. Pacific Northwest market was served under the traditional contract structure where Westcoast and then B.C.P.C., a provincial crown corporation,[11] served as the supply aggregator who in turn sold gas to a single buyer, Northwest Pipeline Corporation (Northwest Pipe), the major interstate pipeline serving the U.S. Northwest. In 1988, Northwest Pipe declared *force majeure* on its contracts with Westcoast.

With the termination of the contracts with Northwest Pipe, U.S. buyers and Canadian sellers have begun to build new contractual relationships. Since 1988, at least thirteen long-term contracts totalling 7.8 10^6 m^3/day (275 MMcfd) have been executed between B.C. and Alberta supply aggregators and producer/marketers and Pacific Northwest LDCs (Figure 2-12). Each of these contracts use the traditional contract structure where the principal sales transaction between the buyer and the seller occurs at the export point, Huntington, B.C. (Figure 2-1). In early 1992, three additional long-term contracts with cogeneration plants located in the U.S. Pacific Northwest were filed with the NEB totalling 1 047.6 10^3 m^3/day (37 MMcfd). (These contracts are not included in the survey.)

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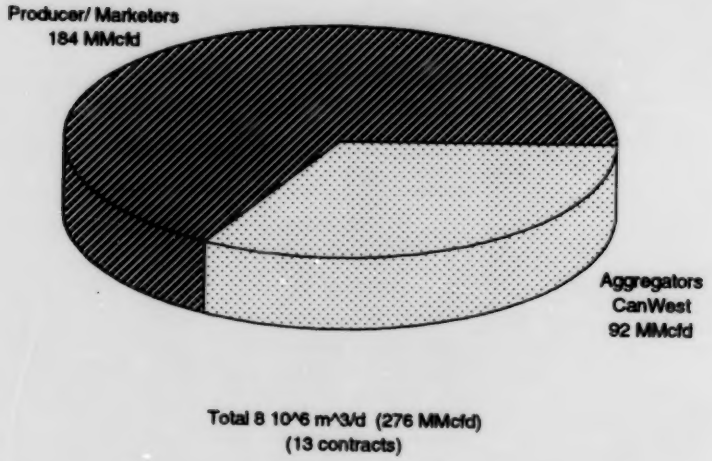
[9] During the fall of 1991, PG&E announced the proposed sale of its pipeline, PGT, to TransCanada.

[10] The contractual chain is Pan-Alberta to Northwest Alaskan Pipeline Company to Pacific Interstate Transmission Company (PITCO). These transactions occur at the export point, Kingsgate, British Columbia. PITCO resells the gas to SoCal at the Arizona/California border. PITCO and SoCal are both subsidiaries of Pacific Enterprises.

[11] The gas purchasing activities of B.C.P.C. were privatized in 1990 and restructured as CanWest.

Figure 2 - 12

Long - Term Canadian Gas Contracted Volumes To The U.S. Pacific Northwest By Type of Suppliers



2.3 The Changing Role of Long-Term Contracts

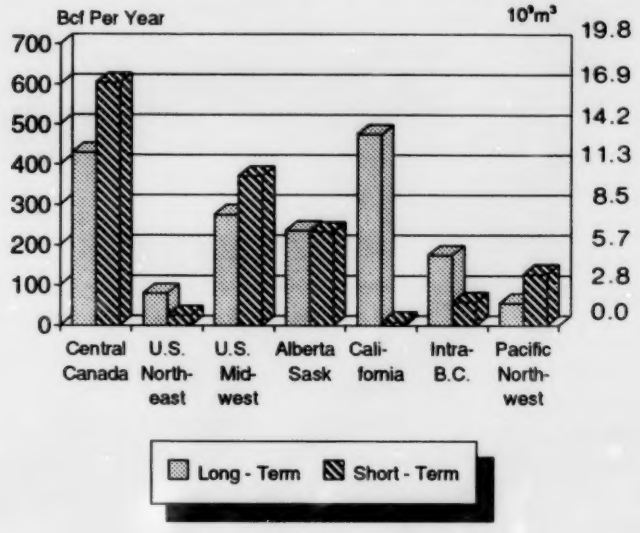
2.3.1 Short vs. Long-Term Contracts

One of the most important changes in the Canadian and U.S. natural gas industry since deregulation has been the increase in short-term sales (a firm obligation to deliver for five years or less, although most short-term sales are for two years or less) and spot gas sales (a best efforts sale to deliver for up to 30 days). Prior to deregulation, almost all western Canadian gas was sold under a chain of long-term contracts except for the last link between the LDCs and end-users where contracts were typically short-term. With the changes that made it feasible for Canadian industrial and commercial consumers to purchase gas directly from producer/marketers and supply aggregators, the use of short-term contracts has become widespread. In the U.S., end-users who purchase gas directly from producer/marketers and supply aggregators typically buy gas on a spot basis. Also, many U.S. LDCs purchase incremental gas requirements on the spot market, including spot gas imports from Canada. Canadian LDCs continue to purchase system gas requirements under long-term contracts largely for use in the residential sector.

Figure 2-13 illustrates on the basis of actual sales in 1990 how important the short-term (spot and short-term firm) sales have become compared to long-term sales of western Canadian gas in each market region.

Figure 2 - 13

Long - Term vs Short - Term Canadian Gas Sales
1990 Actual Sales
by Regional Markets



In the U.S. Northeast, the flow of gas under long-term contract is expected to increase sharply in 1992 and 1993 with the recent opening of the Iroquois pipeline. Also, the flow of long-term volumes will increase to the U.S. Pacific Northwest market region as several contracts negotiated in 1990 and 1991 come into effect.

2.3.2 Changes in Long-Term Contract Volumes Since 1985

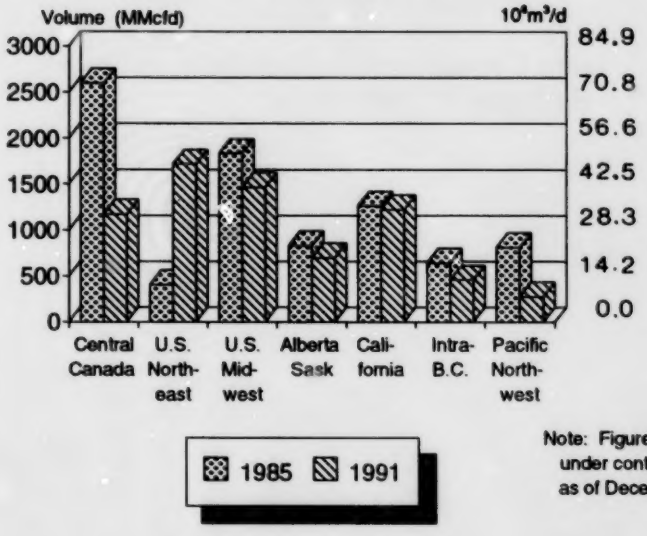
With the emergence of short-term sales since 1985, the volume of gas committed to export and domestic markets under long-term contracts changed significantly. In terms of total contract volumes, the long-term contract volumes have declined 16 percent, from 235 10^6 m^3/day (8,290 MMcfd or 3.0 Tcf annually) to 198.6 10^6 m^3/day (7,000 MMcfd or 2.5 Tcf/year). A decline in long-term contract volumes has occurred in every market region, including domestic markets, except the U.S. Northeast. The change in volumes contracted to each market region is indicated in Figure 2-14.

The sharp drop in volumes contracted on a long-term basis in domestic markets, particularly the central Canadian market, reflects the large number of industrial and commercial consumers who have displaced long-term gas with short-term arrangements. The increase in volumes of gas

committed to the U.S. Northeast reflects the growth in new demand and the need for long-term supply contracts to secure new pipeline transportation capacity and to finance cogeneration projects.

Figure 2 - 14

Long - Term Canadian Gas Contracted Volumes 1985 vs 1991 By Regional Markets



Note: Figure represents volumes under contract to each market as of December 1985 and 1991.

The reduction in the volume of long-term gas contracted to the U.S. Midwest (which has regained its place as the largest export market for Canadian gas) has resulted from the shrinkage of total gas demand in this market region, the U.S. LDC practice of purchasing incremental gas requirements on a spot basis and the reduced demands on the traditional importers of Canadian gas, the U.S. interstate pipelines.

There has been little change in the volume of Canadian gas contracted to the California market since 1985. However, it is expected that the volume contracted on a long-term basis will increase over the next 12 to 18 months as the necessary export applications are filed with the NEB to support the new pipeline capacity that is planned to serve this market.

The load factor, i.e., the actual annual sales quantity of gas compared to contract quantities, on each contract varies widely from contract to contract depending upon the buyer's obligation to purchase, the relationship between long-term and short-term prices, the availability of storage capacity, the availability of pipeline capacity, regional climatic conditions and economic fluctuations.

2.3.3 Purchasers of Long-Term Gas

Not only have total volumes of long-term gas declined, but also the importance of the different types of U.S. buyers has changed. Figure 2-15 illustrates that Canadian and U.S. LDCs remain the largest purchasers of long-term gas. The U.S. cogeneration is a rapidly growing sector. In 1985, there were no sales to cogeneration plants. By the end of 1991, 15 percent of total long-term contract volumes were committed to the U.S. cogeneration sector (Figure 2-16). The importance of U.S. interstate pipelines as purchasers of Canadian gas has declined steadily since 1985.

Figure 2 - 15

Total Long - Term Canadian Gas Contract Volumes By Type of Purchasers

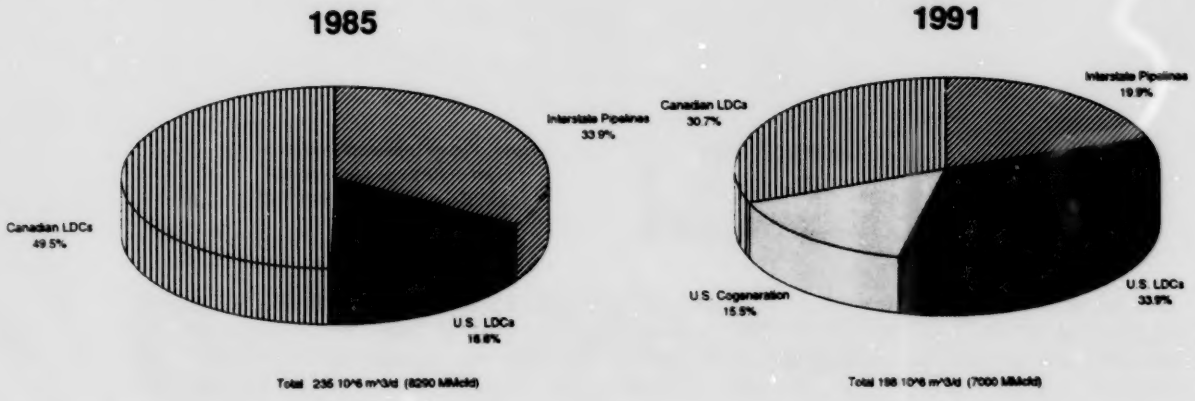
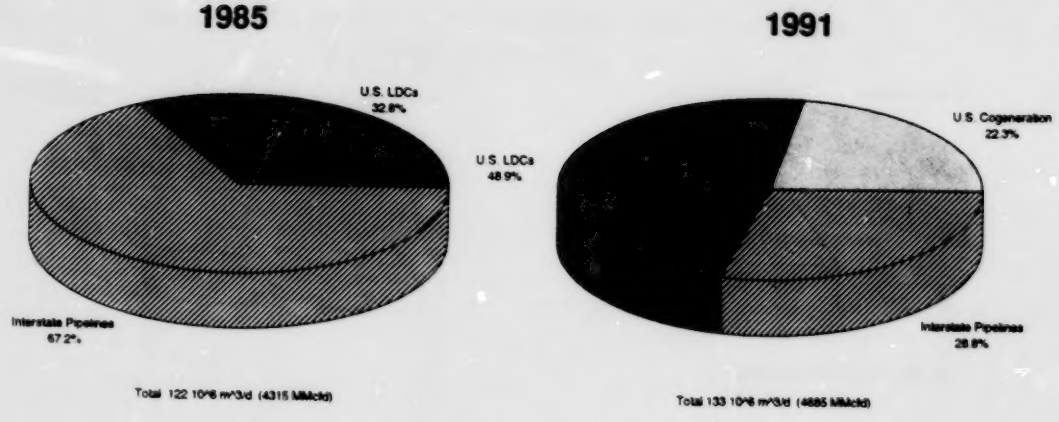


Figure 2 - 16

Long - Term Canadian Gas Contracted Volumes By Type of U.S. Purchasers



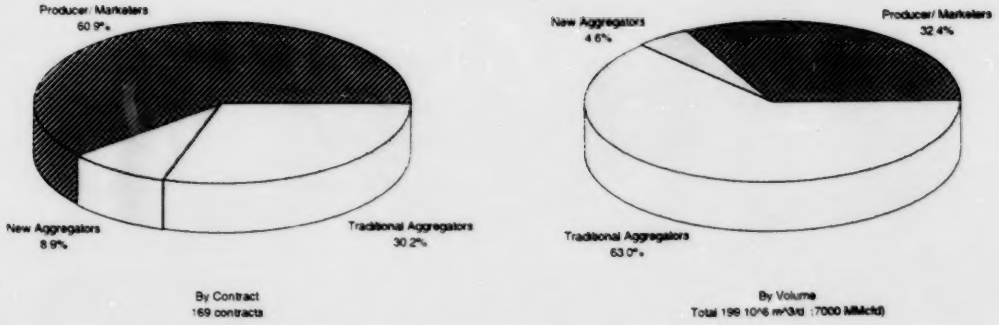
2.3.4 Marketers of Long-Term Canadian Gas

Up to 1985, with exception of the Alberta/Saskatchewan market, all long-term gas was sold to consumer interests by a small number of traditional supply aggregators which included Consolidated Natural Gas Company, Pan-Alberta, ProGas, TransCanada (now WGML), and Westcoast/B.C.P.C. (now CanWest). By 1991, many new participants have entered the market either as producer/marketers (eg., BP Resources Canada Limited, Mobil, Poco, and Shell) or supply aggregators (eg., Direct Energy Marketing, Limited, Northridge and Unigas).

In 1985, all long-term gas outside of the Alberta/Saskatchewan market was sold by traditional supply aggregators. Figure 2-17 below illustrates the share of the long-term market held by different types of gas suppliers.

Figure 2 - 17

Long - Term Canadian Gas Contracts
By Type of Suppliers
1991



2.4 Term or Duration of Long-Term Gas Contracts

The term of a gas contract is dependent on several factors in addition to the seller's desire to secure a long-term market outlet and the buyer's requirements for reliable gas supplies. When buyers and sellers negotiate a gas contract that requires new pipeline capacity to be constructed to transport the gas from the point of production to the point of consumption, other considerations emerge. To secure regulatory approval and financing for new gas pipeline facilities in both Canada and the U.S., it is often necessary to demonstrate a long-term commitment by the buyer to purchase gas and by the seller to deliver gas to ensure that the cost of the pipeline investment will be recovered. Typically, the commitment is demonstrated by a long-term contract for gas sale and purchase and by a matching contract by either the gas seller or the gas buyer for transportation services on the various pipeline systems involved. In addition, buyers such as those constructing cogeneration plants on the basis of project financing may also require a committed supply of gas to meet the financing conditions for the cogeneration plant.

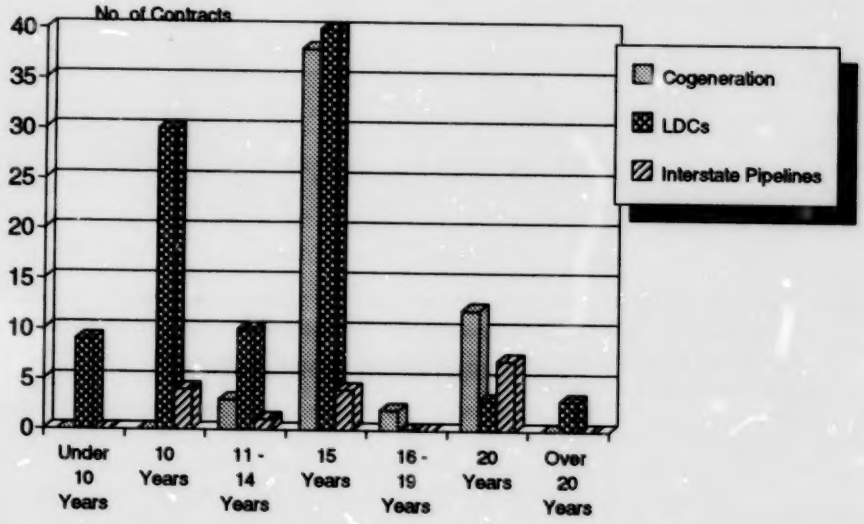
During the 1970's and early 1980's, when there was considerable uncertainty about future supplies of natural gas, buyers would typically contract for the maximum terms allowed by regulators for provincial removal permits or NEB export licences which was 20 or 25 years. In recent years, regulators have been reluctant to approve exports for periods greater than 15 years. In addition,

as concerns over the availability of long-term gas supply abated in the 1980's, contract duration has increasingly been determined by pipeline transportation and financing requirements.

The largest number of export and domestic long-term contracts in force today have 15-year terms (approximately one half or 81 of 169 contracts) and almost all of these contracts are for cogeneration or LDC supply (Figure 2-18). Interstate pipelines make up a small proportion of the total number of 15-year contracts (4 contracts).

Figure 2 - 18

Length of Long - Term Canadian Gas Contracts By Type of Purchasers



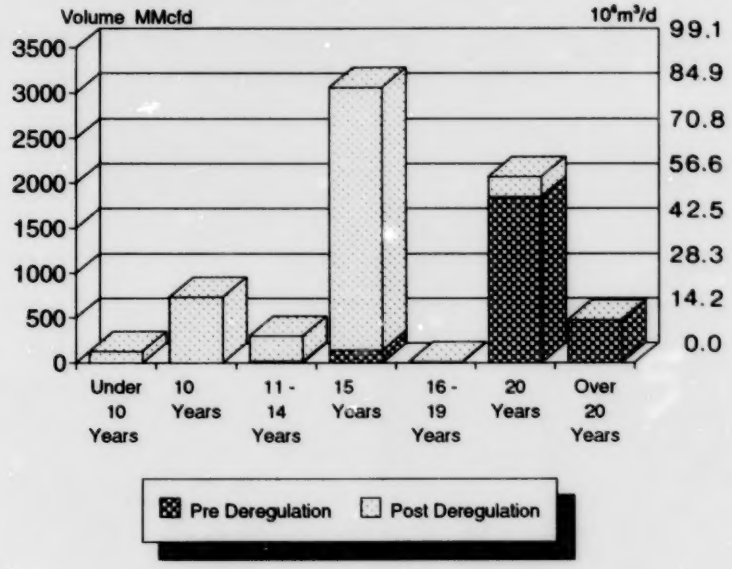
Interstate pipelines tend to contract for longer terms. Approximately 56.6 $10^6 m^3$/day (2 Bcf per day) is contracted under agreements with 20 year terms of which 20.7 10^6 m^3/day (730 MMcfd) or 37 percent is contracted to interstate pipelines. Several smaller cogeneration contracts (12) have 20 year terms. The only LDC's who have contracted for 20 years are SoCal and PG&E in California. The evidence also indicates that over 90 percent of the volume of gas contracted for terms greater than 15 years is supplied by the traditional aggregators.

Figure 2-19 illustrates clearly the trend towards shorter term contracts since deregulation. While the typical contract length with LDCs is 15 years, there are also a large number of more recent LDC contracts with terms of 10 years or less that have been negotiated since price deregulation. It is noteworthy that almost all LDC contracts with terms of ten years replace earlier long-term contracts and have not required major investments in new pipeline facilities. All of the long-term

contracts with terms less than 10 years are with LDCs and none require new pipeline facilities. (In most cases, these contracts are to supply the central Canadian and British Columbia LDCs.)

Figure 2 - 19

Length of Long - Term Canadian Gas Contracts
Pre vs Post Deregulation



Increasingly, parties to long-term contracts are "evergreening" their agreements. That is, the contracts state explicitly that the agreement will continue in force usually on a year by year basis after the initial term unless either party gives notice to terminate the contract (usually one year in advance). In effect, the long-term contract becomes a one year firm gas supply contract. These contracts stipulate that any extensions are conditional on both parties holding the necessary regulatory approvals.

The evidence also suggests that since deregulation, there is a trend to contract gas that will flow on existing pipeline capacity under increasingly shorter contract terms. In circumstances where new pipeline capacity is required or where either the buyer or seller is seeking project financing (eg., new cogeneration plants), the parties will require 15 year and sometimes 20 year agreements.

2.5 Size of Long-Term Contracts

Prior to deregulation, western Canadian gas flowed under a small number of large volume contracts. Typical U.S. purchasers were interstate pipelines who served very large markets through resale to several LDCs. In Canadian markets, buyers were LDCs which by North

American standards are relatively large. Canadian LDCs served as demand aggregators for all market sectors within their franchise, including the industrial sector. Prior to 1985, there were less than 50 long-term contracts, excluding the contracts between Alberta and Saskatchewan LDCs and producers. (The average size of CWNG/NUL and Sask Energy contracts is less than 56.6 10^3 m^3/day (2.0 MMcfd).) The average contract size measured in terms of the DCQ was approximately 3.5 $10^6 m^3$/day (125 MMcfd).

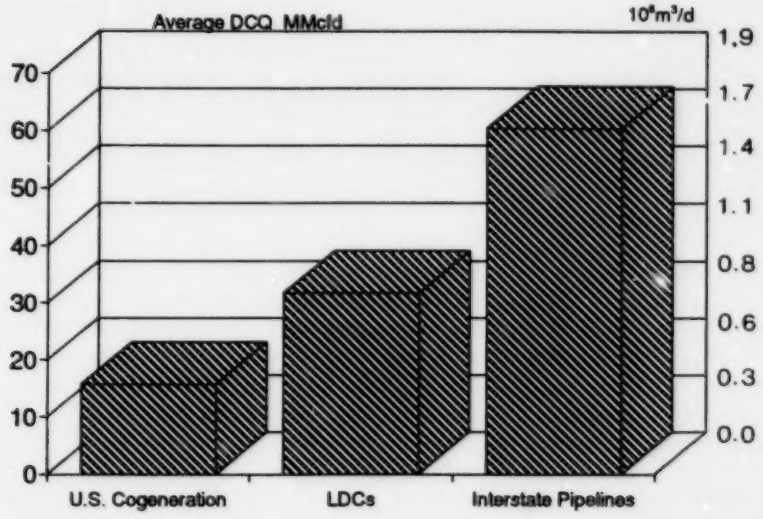
With deregulation, several changes occurred that have had an impact on contract size. First, buyers and sellers sought to diversify their supply portfolios and markets as a means of increasing the reliability of supply and stability of sales. Second, individual end-users, which obviously have smaller gas requirements than demand aggregators, entered the marketplace. To a large extent, direct purchases by end-users have displaced LDC and interstate pipeline system supplies, reducing dramatically their gas requirements in certain market regions. Third, several producer/marketers have entered the marketplace. These companies have smaller supply capabilities than supply aggregators, and generally prefer to diversify their sales through a larger number of smaller contracts.

In addition, 57 agreements have been executed to supply cogeneration contracts. The average size of these contracts is 425 10^3 m^3/day (15 to 16 MMcfd) (Figure 2-20). A 70 MW cogeneration plant, which is a typical plant size, normally requires approximately 425 10^3 m^3/day (15 MMcfd) of fuel. Frequently, cogeneration plants will diversify their gas requirements by purchasing gas from two or more suppliers. An example of a cogenerator who has a diversified supply portfolio is Pawtucket Power Associates Limited Partnership, which will operate a 60 MW cogeneration plant in Rhode Island and has purchased the necessary gas supply from Opinac Exploration Limited and Columbia Gas Development of Canada Limited 181 10^3 m^3/day (6.4 MMcfd) each. Pawtucket has contracted with Brymore Energy Ltd. to administer the supply and transportation arrangements.

The largest number of long-term contracts in the survey are with LDCs (a total of 92, excluding CWNG/NUL and Sask Energy contracts). LDC agreements tend to be considerably larger than cogeneration contracts. The average size of a contract with an LDC is approximately 1.1 10^6 m^3/day (40 MMcfd). However, since deregulation, new LDC contracts have also declined in size. LDC contracts signed since 1985 have an average size of 850 10^3 m^3/day (30 MMcfd). If the exceptionally large ANE/WGML contract (7.8 10^6 m^3/day or 275 MMcfd) in which the repurchasers are 16 U.S. Northeast LDCs and the WGML/central Canadian LDC contracts are excluded, the typical LDC contract size becomes 650 10^3 m^3/day (23 MMcfd).

Figure 2 - 20

Average Size of Canadian Gas Contracts By Type of Purchasers



Interstate contracts have also declined in size since deregulation as many of their customers elect to purchase more gas directly. The average contract size with interstate pipelines in effect prior to deregulation was more than 2.8 10^6 m^3/day (100 MMcfd), compared to 1.7 10^6 m^3/day (60 MMcfd) for contracts signed after 1985. However, there is considerable variation in the size of contracts with interstate pipelines.

Not surprisingly, most of the large volume contracts over 1 10^6 m^3/day (35 MMcfd) are supplied by the traditional aggregators, WGML, ProGas, CanWest and Pan-Alberta, which control the gas reserves necessary to support large contracts. The average size of contracts negotiated by producer/marketers is 570 10^3 m^3/day or 20 MMcfd.

2.6 Summary

Since natural gas deregulation in the mid 1980s, several important trends have emerged in the structure of long-term natural gas contracts. The rate of change, however, has been uneven across the major regional markets for western Canadian gas.

The greatest change has been experienced in contracts governing the sale of gas to central Canada and the U.S. Northeast. The contracting practices that have developed in these two markets since

1985 have set the pattern of change in other markets such as the U.S. Pacific Northwest and British Columbia. Fewer changes have been observed in the U.S. Midwest market where several pre-1985 contracts remain in force. There has been virtually no change in the structure of contracts serving the Alberta/Saskatchewan market or the California market. In the case of California, significant changes are expected over the next two years that may establish further trends in contracting.

The following are the principal trends in the contractual structure of the market for Canadian gas which have emerged over the past seven years:

1. There has been a tremendous increase in the proportion of the market served by firm short-term and spot sales of natural gas. The growth of short-term sales has been greatest in the U.S. Midwest and central Canada. The trend towards short-term gas contracts is expected to continue in markets where buyers and sellers have access to existing pipeline capacity. Most long-term contracts negotiated since deregulation have initial terms of 15 years, although the number of contracts with terms of 10 years or less is growing rapidly.

2. Cogeneration has emerged as a major new market sector for long-term sales in both Canada and the U.S. (The Canadian cogeneration sector is not documented in this report.) To date, growth of the cogeneration sector has been strongest in the U.S. Northeast. A potential additional sector for natural gas under long-term contracts is electric utilities, although there have been only a small number of contracts negotiated by the end of 1991.

3. The importance of U.S. interstates and Canadian LDCs, the traditional purchases of gas under long-term contracts, has greatly declined, whereas U.S. LDCs purchasing Canadian gas directly from aggregators and producer/marketers has increased.

4. Producer/marketers and new aggregators have entered the market in large numbers. These new players have been very active entering into contractual arrangements of all kinds. The traditional supply aggregators have also continued to be active but have lost approximately 35 percent of the long-term market (by volume) to new entrants.

5. A large number of buyers have elected to purchase gas upstream of the major pipeline systems and to contract with the transmission companies for the necessary transportation capacity.

6. Contractual arrangements have become much more numerous, and the typical contract much smaller. This is a reflection of multiple buyers and sellers and of the fragmentation of the supply and demand aggregation functions.

Chapter 3

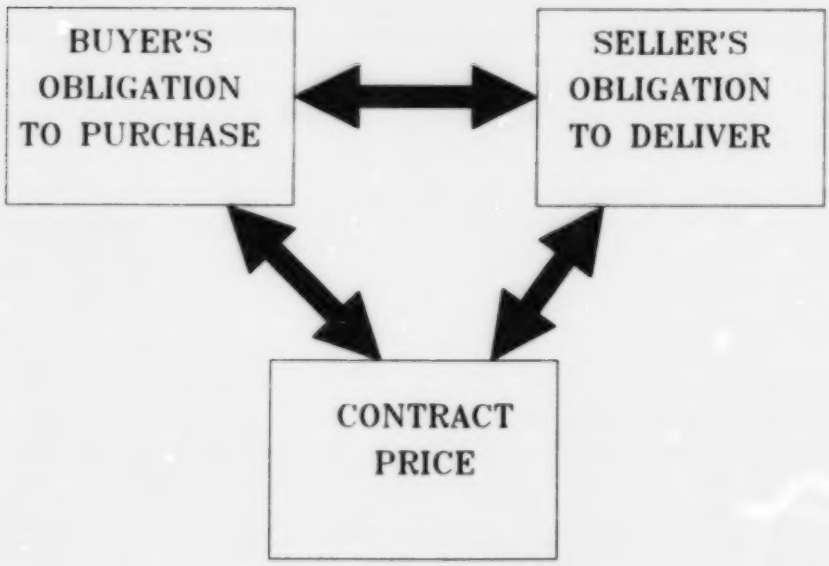
Terms and Conditions of Long-Term Canadian Natural Gas Contracts

Unlike short-term or spot gas contracts which are highly standardized, long-term contracts are often unique combinations of terms and conditions negotiated to meet the particular requirements of both the buyer and the seller. The primary purpose of most long-term contracts governing the sale of western Canadian natural gas is to secure a reliable supply of gas for the buyer and a long-term market outlet for the seller and to establish the basis for an enduring business relationship. Therefore, the terms and conditions of a contract that determine the buyer's obligation to purchase and the seller's obligation to deliver are of paramount concern.

The actual terms and conditions employed to secure the key elements of a contract, the buyer's obligations, the seller's obligations and contract price, depend upon whether the buyer is a cogeneration plant, an LDC or an interstate pipeline (Figure 3-1). Terms and conditions also depend on whether the seller is a large or small producer/marketer or whether the seller is a supply aggregator. The balance between the buyer's obligations and the seller's obligations and the relationship between this balance and the contract price depend on the individual requirements of the parties as well as their perception of the risks involved and the market conditions at the time the contract is negotiated.

Figure 3 - 1

Key Elements of Long - Term Canadian Gas Contracts



Only a small number of long-term contracts (11) for western Canadian gas have the gas price fixed for the full term of the agreement. Instead, most contracts have flexible pricing terms that allow the contract price to track changing market conditions. The pricing mechanisms may also include specific adjustments that reflect the cost of the terms and conditions securing the buyer's and seller's obligations (eg., Gas Inventory Charges).

Care must be exercised then when evaluating elements of a gas contract such as the contract price in isolation of other key elements. The three key elements of a contractual relationship are closely interrelated and must be viewed as a whole when making comparisons with other contracts. Similarly, the balance between the major elements of a contract will shift with changing market conditions, and caution must be exercised when comparing contracts executed at different points in time. Nevertheless, it is useful to break a contract down into the three elements for the purpose of identifying and understanding trends that may be emerging with respect to the use of key terms and conditions.

The objective of this Section is to examine the trends in the terms and conditions used to secure the buyer's obligation to purchase as well as trends with respect to the seller's commitment to deliver. The shift in balance between these two key elements since deregulation is also discussed. In addition, common pricing principles in long-term contracts are reviewed and recent trends are identified.

3.1 Buyer's Obligation to Purchase Gas

From the perspective of most sellers, the primary purpose of a long-term contract is to secure a stable outlet for a portion of its gas production. In order to ensure that the objective will be achieved over the term of the contract, and before committing to meet the buyer's requirements on demand, sellers will secure the buyer's commitment to purchase at least a significant proportion of the annual contract quantity.

There are two major risks that sellers face when they enter a firm, long-term contract with a buyer. First, the possibility exists that the buyer may permanently lose its market as a result of a structural change in demand. This is what occurred in many U.S. markets when energy demand shifted away from natural gas in the industrial and electrical generation sectors in the late 1970's and early 1980's. It would also include structural charges resulting from economic forces causing plant closings and the trend to de-industrialization. It also occurred in both Canada and the U.S. after deregulation in 1985 as industrial and commercial end-users elected to purchase gas directly from producer/marketers rather than from the traditional demand aggregators, such as LDCs and interstate pipelines.

The second risk is the possibility of buyers "shopping the market", i.e., buyers purchasing gas from other suppliers, including spot gas, usually at prices lower than the long-term contract price, before the contact quantities are fully nominated.

There are several mechanisms that are used in gas contracts to reduce these risks and establish the buyer's obligation to purchase gas. Trends in the application of each of these mechanisms since deregulation are discussed below.

3.1.1 Take-or-pay Commitments

Take-or-pay is defined for the purpose of this report as an obligation by the buyer to purchase a specific volume of gas over a defined period (eg., 50 or 60 percent of the Monthly Contract Quantity (MCQ) or the Annual Contract Quantity (ACQ)). If the buyer fails to purchase the specified volume (assuming that the seller was able to deliver the gas) for reasons other than force majeure, it is nevertheless obligated to pay for the gas usually at the current commodity price.

In effect, the buyer has prepaid for the gas and may recover the prepaid balances usually over at least the next two or three years and often over the remaining term of the agreement subject to the availability of transportation capacity. The price of prepaid gas when it is delivered varies from contract to contract. Normally, the price is the same as the prepaid price. However, some contracts require that any differential between the prepaid price and the price at the time of delivery be paid to either the buyer or seller.

Although less than a quarter of the long-term contracts are backed by take-or-pay, these contracts account for one third of the total volumes in the population of long-term contracts examined. Figure 3-2 shows the number of contracts negotiated since deregulation with take-or-pay provisions.

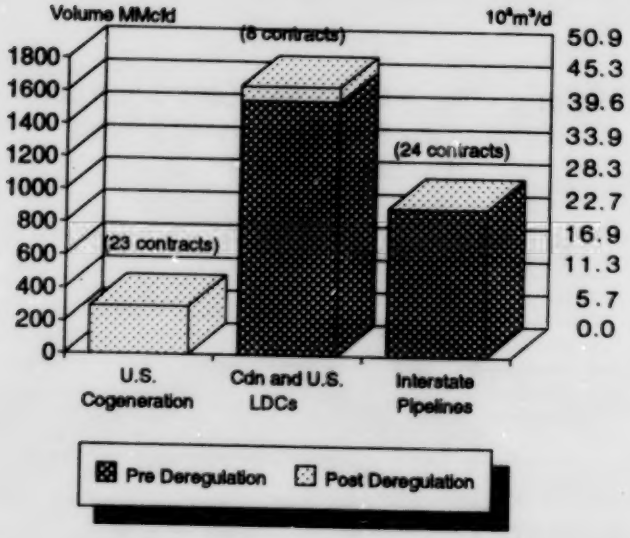
During the 1970's, most export contracts, as well as the contracts between the supply aggregators and producers, secured the buyer's obligation to purchase contract quantities through take-or-pay provisions that required the buyer to pay either monthly or annually for most, if not all, of the gas under contract, regardless of whether it actually took the gas. Take-or-pay levels of 90 and 100 percent were not uncommon. Figure 3-3 shows the current take-or-pay threshold levels of long-term Canadian gas contracts.

However, in the 1980's U.S. gas demand declined precipitously in many markets and several U.S. demand aggregators (i.e., interstate pipelines and LDCs) were unable to resell all of the Canadian gas they had under contract and began to accumulate large take-or-pay balances that placed serious financial strains on buyers. Through a series of complex negotiations and settlements, almost all of the U.S. LDC and interstate pipeline contracts negotiated during the 1970's have either eliminated or reduced significantly the take-or-pay commitments. Only two contracts negotiated with demand aggregators since deregulation that are included in the survey include take-or-pay provisions (CanWest/Northwest Natural Gas Company and Amoco/NSP). All other contracts in the survey with take-or-pay clauses negotiated since deregulation have been in the cogeneration sector.

Unlike other markets, in Alberta and Saskatchewan a large number of the contracts negotiated in the 1960's and 1970's between CWNG/NUL and Sask Energy (the two major demand aggregators), and producers continues to be backed by high take-or-pay commitments. In the central Canadian market, the only contract that included a take-or-pay commitment is the agreement between Pan-Alberta and GMi also negotiated in the 1970's and which has since been removed as a contract term in 1992. In the B.C. and central Canadian markets, none of the contracts negotiated by the LDCs since deregulation include take-or-pay commitments.

Figure 3 - 2

Long - Term Canadian Gas Contract Volumes Backed by Take - Or - Pay By Type of Purchasers



As long as buyers are confident that they will require most of the gas they have under contract, take-or-pay provisions are effective in securing the buyer's obligation to purchase. However, there is a trend away from take-or-pay by buyers who are purchasing gas for the purpose of resale (i.e., demand aggregators). Where take-or-pay is used, the threshold levels have often been reduced to avoid the difficulties experienced in the early 1980's and the uncertainty that surrounds demand aggregators due to the shift to direct purchases by many end-users. Also, U.S. regulations, such as FERC Order 380[12] which limits the ability of interstate pipelines to recover take-or-pay costs from customers, have contributed to the trend away from take-or-pay.

At least 23 cogeneration contracts negotiated since deregulation have some form of take-or-pay, including a small number of contracts in which the buyer prepays for the total contract quantity through an upfront lump sum payment to the seller before gas begins to flow. The latter contracts are in effect 100 percent take-or-pay contracts in which the seller has no obligation to refund the buyer for gas not taken until the end of the contract term when some of the contracts require a refund of all or part of any remaining prepaid balances without interest. (In contracts where the buyer has prepaid for all the gas at the beginning of the contract, the sellers must normally maintain an irrevocable letter of credit covering the value of the prepaid gas.)

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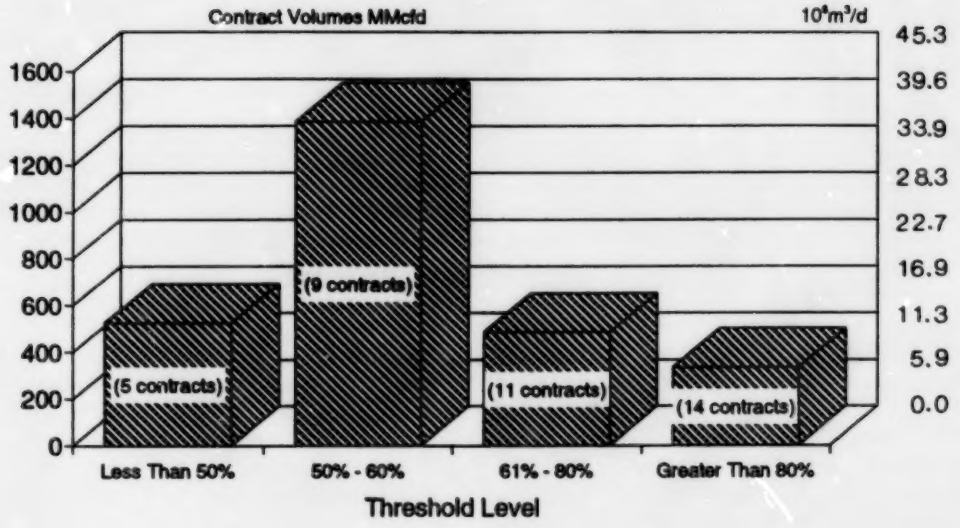
[12] FERC Order 380 - U.S. Federal Energy Regulatory Commission's 1984 Order that disallowed non-incurred gas costs, such as take-or-pay payments, from the minimum commodity bills of U.S. interstate pipelines.

Recognizing the large financial risks to buyers posed by traditional take-or-pay clauses, ProGas has developed a take-or-pay mechanism with some of its cogeneration customers whereby the buyer must pay regularly a carrying charge on any volume shortfalls (eg., the Canadian Imperial Bank of Commerce prime rate plus 2 percent times the commodity price), thereby avoiding the financial strain of prepayments that traditional take-or-pay can impose on a buyer. Other cogeneration buyers have agreed to take-or-pay commitments between 60 to 80 percent of the ACQ in which any prepaid balances may be recovered usually over 3 to 5 years and any remaining balances are repaid to the buyer without interest.

Figure 3 - 3

Long - Term Canadian Gas Contract
Take - Or - Pay Threshold Levels
Percentage of DCQ



3.1.2 Deficiency Payments

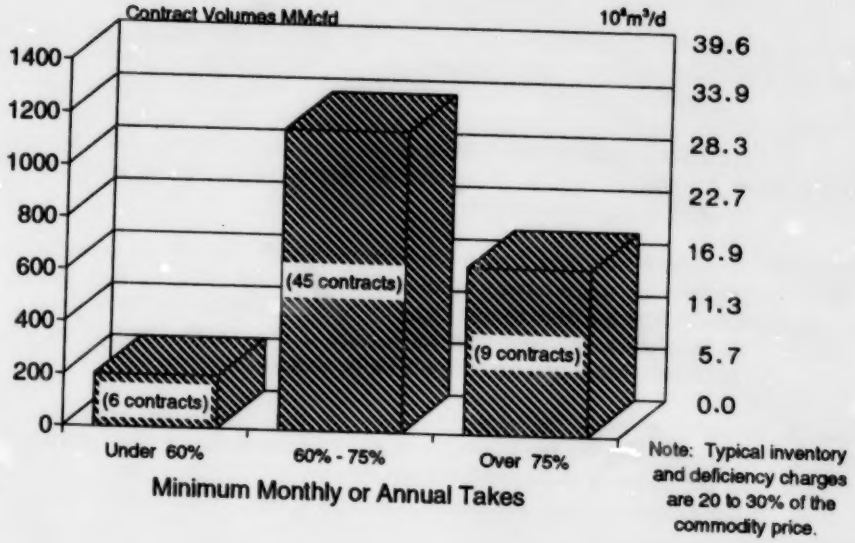
Several contracts negotiated since deregulation include a deficiency payment, reservation charge or a gas inventory charge (GIC). Although deficiency payments or their equivalent can be structured in different ways, they have evolved from the traditional take-or-pay mechanisms and have a similar impact.

The important difference between an obligation to make a deficiency payment or GIC and a take-or-pay obligation is that under take-or-pay the buyer is in effect prepaying for gas. A deficiency payment is an explicit or implicit recognition of a minimum level of costs that the seller must incur to be capable of meeting its contract commitments. Deficiency payments are generally not

recoverable in future periods (in a small number of cases, the buyer can recover deficiency payments in the first year or two after payment only).

Figure 3 - 4

Long - Term Canadian Gas Contract Deficiency Charge or GIC Threshold Level Percentage of ACQ



Prior to deregulation, the only contracts that included a deficiency payment or equivalent were the contracts between Pan-Alberta and the interstate pipelines, Panhandle Eastern Pipe Line Company and Northern Natural Gas Company (Northern Natural). Since deregulation, at least 40 contracts have been executed that include a deficiency payment, reservation charge or GIC. The typical threshold volume of a deficiency payment and GICs is 60 - 75 percent of the ACQ (Figure 3-4).

Several (6) of the new contracts into the U.S. Pacific Northwest and most of the contracts with BC Gas Inc. include GICs. The most important contracts with reservation charges are the agreements between WGML and the Ontario and Québec LDCs. Under certain circumstances,[13] reservation charges in the WGML/LDC contracts are refundable without interest after two years.

GICs, reservation and deficiency charges are relatively recent concepts that have not been tested extensively. They are designed to assure the seller a minimum level of revenue while at the same time providing the buyer with an incentive to purchase threshold volumes of gas. They are

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[13] If demand falls below contract levels as a result of climatic or economic conditions, reservation fees are refundable.

frequently used by sellers marketing gas to interstate pipelines and LDCs. To date, they have not been used extensively in cogeneration contracts.

3.1.3 Pipeline Demand Charges

Almost every gas contract in the survey in which the seller must hold capacity on a regulated pipeline to deliver contract quantities to the point of sale requires the buyer to pay the regulated monthly demand charge for pipeline capacity held by the seller. Pipeline demand charges must be paid by the buyer, regardless of whether full contract quantities are purchased.

Although gas buyers consider their obligations to pay pipeline demand charges as "sunk costs" when making daily or monthly purchase decisions, many sellers rely on demand charges to encourage the buyer to nominate at a high load factor. The evidence indicates that over the last decade demand charges have not reinforced the buyer's obligations to purchase, particularly in the case of buyers who have a diversified supply portfolio and have access to more than one pipeline. Demand charges have provided minimal protection to the seller except against the cost of unabsorbed pipeline demand charges.

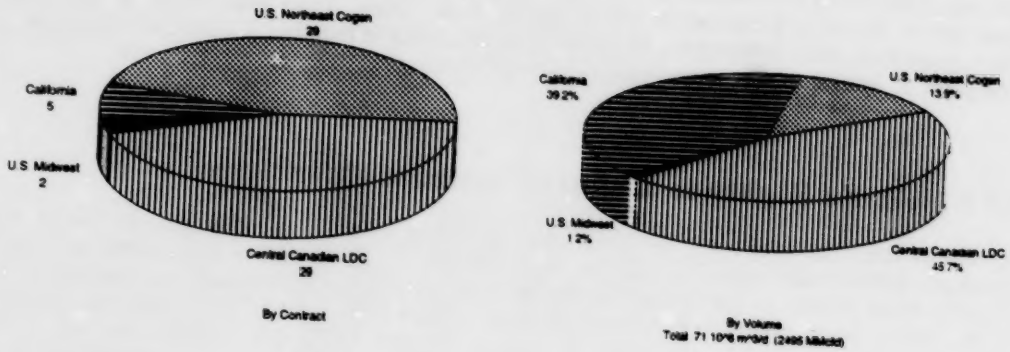
Prior to deregulation, contracts were silent regarding the disposition of unused pipeline capacity held by the seller during periods when buyers nominate less than the DCQ. Although the buyer paid the demand charges, sellers are able to use capacity upstream of the delivery point to make third party sales, which is often a valuable contract feature if the point of sale is an important marketing point (eg., Emerson, Manitoba or Niagara Falls, Ontario).

In circumstances where the point of sale is close to the producing regions (eg., the Alberta/Saskatchewan border) and the transportation capacity downstream of this point is held by the buyer (Figure 3-5), the demand charge obligations, if any, are relatively low and the risk of the buyer "shopping the market" within the production region (eg., Alberta and Saskatchewan) increases substantially.

There has been an important trend towards buyers rather than sellers contracting for the required pipeline capacity. Since deregulation, 65 contracts totalling almost 70.8 10^6 m^3/day (2,500 MMcfd) have been negotiated where the buyer holds the pipeline capacity downstream of Alberta.

Figure 3 - 5

Long - Term Canadian Gas Contracts At Alberta Border Point of Sale



Many contracts (35) written since deregulation explicitly state that the seller may use the buyer's unutilized pipeline capacity to make third party sales and, in certain cases, the seller has given the buyer an undertaking to use its best efforts to make such sales and to credit all or part of the pipeline demand charges recovered through third party sales back to the buyer. These are particularly important rights when the point of sale is close to the point of production, such as the inlet to the TransCanada system.

3.1.4 No Self-Displacement

As noted earlier, one of the most serious risks that sellers face in a long-term contract is the potential for the buyer to "shop the market", purchasing gas from other sellers usually at prices below the contract before purchasing full contract quantities. A simple mechanism that has come into use since deregulation to address this risk is an explicit commitment by the buyer that it will not purchase incremental gas supplies before it has nominated its full contractual entitlement. If the buyer's nominations fall below contract levels, wherever possible the shortfall must be allocated across all firm suppliers to the buyer on a pro rata basis.

More than 50 contracts in the survey include some form of no self-displacement (NSD) commitment. In a few cases, the commitment not to self-displace is only binding if the seller's

gas is competitively priced or the commitment is only limited to Canadian gas (i.e., the buyer has only committed not to purchase other Canadian gas if it has not purchased full contract quantities.)

NSD clauses are widely used in contracts which have minimal demand charge obligations, particularly in cases where the point of sale is at the inlet to TransCanada or Alberta Natural Gas Company Ltd pipeline system, as a means of securing the buyer's performance. Some of the strongest commitments not to self-displace are found in the 30 long-term contracts with the central Canadian LDCs that have been negotiated since 1987. Every central Canadian LDC contract includes an NSD clause. Several contracts to supply U.S. cogeneration plants also include NSD clauses under which the owners have committed not to use third party gas to fuel a cogeneration plant unless the seller's contract is being fully utilized. Often, the contract states further that if the cogeneration plant requires supplemental gas, the owner is required to give the existing seller first right of refusal to supply additional gas requirements.

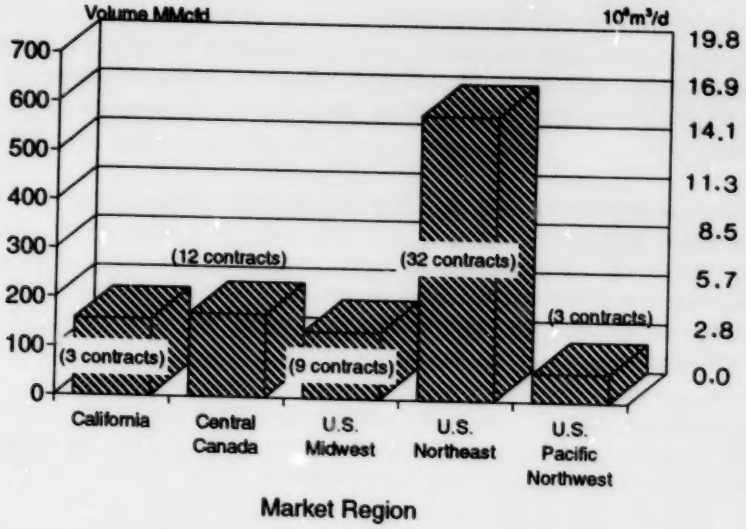
3.1.5 Seller's Rights to Reduce Contract Quantities

A serious risk that long-term contracts pose for sellers is the possibility that the buyer will nominate substantially below the DCQ or ACQ over an extended period of time usually as a result of a structural change in gas demand similar to what occurred in several U.S. gas markets in the early 1980's. Many contracts executed during the 1970's require the seller to maintain adequate deliverability committed to the buyer to supply the full DCQ even though the buyer has consistently nominated well below the DCQ for several years. In these circumstances, the seller has no flexibility to reduce the DCQ without the consent of the buyer.

To provide protection against this risk, there is a trend among sellers entering into new contracts to include the right to reduce the contract DCQ if a minimum level of gas is not nominated over a one or two year period (often referred to as an Annual Trigger Quantity or ATQ). Figure 3-6 shows the long-term Canadian gas contract with ATQ's.

Figure 3 - 6

Long - Term Canadian Gas Contracts With Annual Trigger Quantities



Typical Annual Trigger Quantities are 60 to 80 percent of the ACQ, although most are over 70 percent and some are as high as 100 percent. In the event that the buyer fails to purchase the ATQ, the seller has the right to reduce the DCQ by a proportion of the shortfall. For example, if the ATQ is 70 percent of the ACQ and the buyer purchases 60 percent of the ACQ, the seller may permanently reduce the DCQ and the ACQ by 70 percent of the shortfall below the ATQ.[14] In certain cases, the buyer has the opportunity to purchase the deficient volumes in the subsequent year before the seller may exercise its rights.

The primary purpose of ATQs is to protect the seller against chronically low load factors that might result from a structural or fundamental change in the buyer's demand pattern. They enable the seller to unilaterally release gas reserves, deliverability and transportation capacity from a contract, and recontract these resources to other buyers.

ATQs are a recent trend that first emerged in the U.S. Northeast contracts negotiated in the mid 1980's (eg., WGML/Boundary Gas, Inc.). They have since been used widely in Canadian and

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[14] Reduction Right = $\frac{.7\ (.7\ ATQ - .6\ ACQ)}{365}$

Revised DCQ = Initial DCQ - Reduction Right

U.S. LDC and cogeneration contracts often in conjunction with other terms and conditions designed to secure the commitment to purchase contract quantities.

3.1.6 Operational Demand Volume Adjustment Mechanisms

As noted above, one of the key risks of long-term contracts for sellers is the possibility that the buyer, particularly the demand aggregator purchasing large volumes for resale, loses its customer base. This can occur for several reasons, including loss of sales to other gas marketers which has occurred on a large scale since deregulation as many end-users elect to purchase gas directly from producer/marketers.

This is also a major risk for buyers such as LDCs and interstate pipelines, particularly if a gas supply contract includes deficiency charges or reservation fees that must be paid regardless of whether the gas is taken or not. While sellers often protect themselves against this risk with ATQ clauses that permit them to decontract volumes, several buyers have also protected themselves against the loss of sales and market opportunities to competitors with Operational Demand Volume Adjustment mechanisms (ODV clauses).

An ODV clause allows the buyer to reduce the contract quantity either monthly or annually by the amount in which sales have been lost to other gas marketers. The lost sales volume is normally pro rated across all the buyer's long-term suppliers.

To date, ODV clauses have been used most extensively by the LDCs serving the central Canadian and British Columbia markets. Almost all the long-term gas supply contracts negotiated since 1986 by the LDCs include an ODV clause. The CWNG/NUL contracts with producer/marketers have a "market out" clause which enables the buyer to reduce contract quantities if its gas requirements decline. Northern Natural, a large interstate pipeline serving the U.S. Midwest, has also negotiated an ODV clause in each of the five long-term contracts negotiated with Canadian sellers over the last two years. In the U.S. Northeast market, the large (51 MMcfd) contract between WGML and Niagara Mohawk Power Corporation, an LDC serving upstate New York, includes an ODV mechanism.

The four recent contracts between SoCal Edison, a large California electric generating utility, and Canadian suppliers contains a more general ODV mechanism that permits the buyer to reduce contract quantities if technological innovations, environmental regulations or customer conservation and load management techniques reduce its gas requirements. SoCal Edison must give its suppliers two years notice before exercising its right to permanently reduce contract quantities and it must pro rate the reduction across all its firm suppliers.

3.2 Seller's Commitment to Deliver

Buyers purchase gas under long-term contracts to ensure that they will have a reliable and secure gas supply over an extended period of time, particularly during periods of peak demand. Therefore, the obligation of the seller to deliver contract quantities is also an integral part of a long-term agreement. Several mechanisms are used to secure the seller's commitments. The

choice of mechanism depends upon the practices and policies of the buyer and seller, the type of seller, the nature of the buyer's commitment to purchase and current industry practices. Trends in the use of the most common mechanisms are discussed below.

3.2.1 Dedicated Reserves

Of major concern to a buyer is that the seller will have adequate gas reserves, deliverability and pipeline transportation to be able to deliver contract quantities throughout the term of the agreement. One mechanism used by parties to reduce the risk of a supply failure is dedicated reserves, sometimes referred to as reserve based contracts.

In general terms, dedicated reserves require the seller to set aside specific physical gas reserves under its control to fulfil the commitments of a gas contract. Dedicated reserves normally restrict the seller from selling gas from the reserves to others without the permission of the buyer.

Prior to deregulation when almost all gas was sold to buyers through supply aggregators, the primary sales contracts between buyers and sellers were deliverability contracts that were not backed by dedicated reserves. Most producers selling gas into a supply aggregator's pool do so on the basis of reserve based contracts. However, as buyers began to purchase gas directly from producer/marketers, many have required the seller to dedicate specific reserves to the contract.

Thirteen contracts, i.e., approximately one-half of the non-WGML contracts between central Canadian LDCs and marketer/producers totalling 15 percent of the total contracted volume to this market, are reserve based contracts supported by dedicated reserves. In Alberta and Saskatchewan, most long-term contracts between CWNG/NUL and Sask Energy, and producers are backed by dedicated reserves. In B.C., 20 percent of the volumes contracted by BC Gas Inc. over the past 24 months are based on dedicated reserves. Almost half (41 percent) of the contracts with U.S. Northeast cogeneration plants (31 percent by volume) are based on dedicated reserves.

In general, smaller producer/marketers tend to secure their commitment to deliver with dedicated reserves. Supply aggregators (eg., CanWest, ProGas, WGML) and large producer/ marketers that have a diversified supply base (eg., Amoco, Esso Resources Canada Limited, Mobil and Shell) normally contract on the basis of deliverability agreements and, as a rule, do not dedicate reserves as a means of securing their commitment to deliver.

3.2.2 Corporate Warranties

Supply aggregators and larger producer/marketers frequently secure their obligations to deliver under deliverability contracts through corporate warranties without committing or dedicating specific reserves. Corporate warranties take several forms. They can be a relatively straightforward contractual commitment by the seller that it will maintain adequate reserves and deliverability to meet their obligation to deliver nominated volumes over the term of the agreement. Alternatively, a corporate warranty can be a specific commitment to maintain a specified level of total reserves relative to the seller's total contractual commitments (eg., a reserve to production ratio equal to or greater than 10 is common).

Supply aggregators who do not have a large asset base may offer buyers a corporate warranty that requires the seller to maintain a minimum reserve level which is backed by the reserves that have been dedicated to the aggregator's supply pool by producers. The larger producer/marketers (eg., Gulf Canada Limited, Shell,) will typically offer a more general commitment to maintain adequate reserves and deliverability. For example, the seller may commit to "beneficially own and control sufficient gas reserves and deliverability to meet its obligations during the term of the contract." Sellers also often commit not to over-contract their reserves.

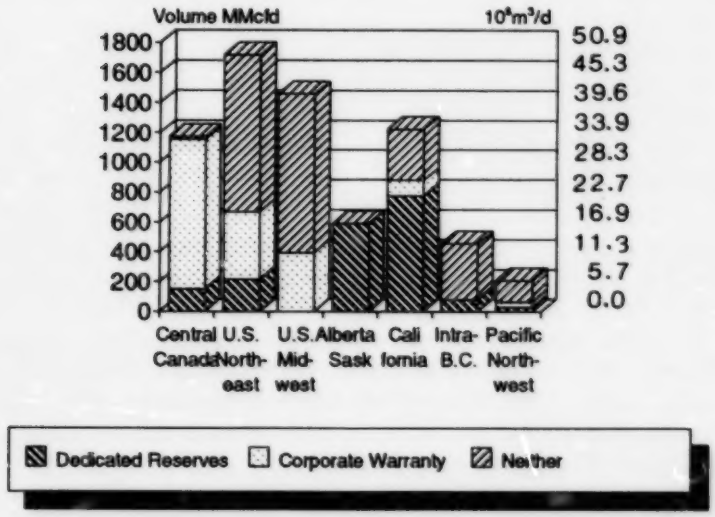
The buyer normally has the right to periodically audit the seller's reserves, deliverability and transportation contracts, as well as the seller's commitments to deliver to other buyers to ensure that the seller is not over-contracted. Alternatively, the seller may be required to provide a regular report (eg., bi-annually) of its reserves prepared by a recognized independent reservoir engineering firm.

As part of the supply warranty, if the seller's reserves and/or deliverability fall below the specified level, the seller is obligated to take corrective action. Failure to take appropriate action usually gives the buyer the right to reduce the contract quantities to a level that can be supported by the seller's reserves or production capability.

All of the long-term contracts to supply the central Canadian market negotiated since deregulation that are not backed by dedicated reserves are backed by corporate warranties (Figure 3-7). Approximately one third of the volumes contracted to the U.S. Midwest are backed by corporate warranties. No contracts to supply gas to the Midwest are backed by dedicated reserves.

Figure 3 - 7

Seller Commitment To Deliver
Under Long - Term Canadian Gas Contracts
Dedicated Reserves vs Corporate Warranties
By Market Regions

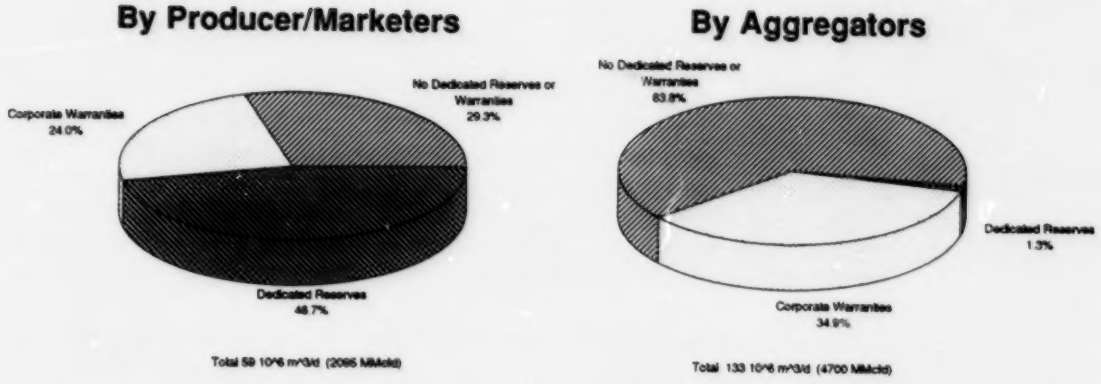


More than 50 percent of the volume of western Canadian gas committed under the long- term contracts included in the survey is backed by either dedicated reserves or an explicit corporate warranty. Most of the contract volumes that are not backed by either type of commitment are supplied by the major supply aggregators which typically supply gas from pools that are backed by dedicated reserves. (It is noteworthy that approximately 50 percent of the contracts that are not backed by either dedicated reserves or a corporate warranty were contracted prior to deregulation.) (Figure 3-8)

Based on the evidence, there is a trend towards securing the seller's commitment to deliver over the term of the agreement through corporate warranties rather than dedicated reserves, although smaller producer/marketers may continue to rely on reserve-based contracts to secure their commitments to deliver.

Figure 3 - 8

Seller Commitment To Deliver
Under Long - Term Canadian Gas Contracts



3.2.3 Buyer Rights to Reduce Contract Quantities

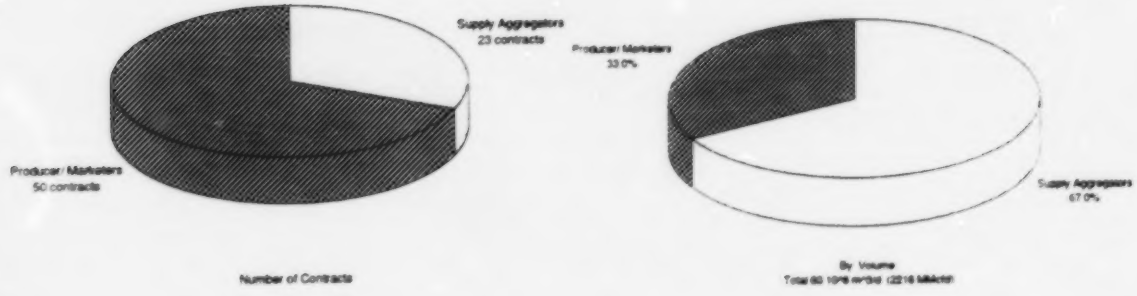
More than 70 contracts accounting for 30 percent of contracted volumes state explicitly that the buyer can reduce the contract quantities if the seller fails to deliver nominated volumes for reasons other than force majeure (Figure 3-9). Typically, if sellers fail to deliver 90 to 100 percent of nominated volumes over periods as short as three months but more commonly over periods of one year, the buyer has the right to reduce the daily contract quantities by the average daily deficiency in deliveries over the specified period. Such measures protect the buyer in a long-term contract

from a situation where a seller experiences difficulties delivering the buyer's nominations on an extended basis.

Terms and conditions that allow the buyer to reduce contract quantities if the seller is unable to deliver nominated volumes on a sustained basis have only emerged in gas contracts since deregulation. The trend reflects the importance that buyers attach to reliability of supply when entering into a long-term contract. It may also reflect the higher level of uncertainty perceived by buyers about the capability of smaller producer/marketers to deliver gas on a sustained basis compared to the traditional supply aggregators. Nevertheless, several contracts with aggregators also give the buyer the right to reduce contract quantities if the aggregator fails to deliver full nominated quantities (eg., WGML's contracts with Boundary Gas, Inc. and ANE allow the buyers to reduce the DCQ if WGML fails to deliver nominated volumes over 120 days).

Figure 3 - 9

Long - Term Canadian Gas Contracts
With Buyer Right To Reduce DCQ
Aggregators vs Producer/Marketers



3.2.4 Seller Indemnities

The primary risk that buyers face in the event that a seller fails to deliver nominated volumes is the possibility of having to purchase make-up gas supplies at premium prices and/or bear pipeline penalties and unabsorbed demand charges on contracted pipeline capacity.

An important trend today is to include specific clauses in long-term gas contracts in which the seller explicitly indemnifies the buyer against specific costs that may arise as a result of a failure

by the seller to deliver nominated volumes of gas. The most common costs that are included are: i) the incremental cost of replacement gas; and ii) the cost of unabsorbed demand charges.

The use of seller indemnity clauses is widespread. More than 90 contracts negotiated since deregulation include some form of specific indemnity against costs that the buyer may incur as a result of delivery shortfalls. Seller indemnities were non-existent in gas contracts prior to deregulation.

3.2.5 Daily Obligations to Deliver

Under most firm contracts, the buyer may nominate up to the DCQ each day and the seller is committed to meet the nomination. However, a number of contracts executed since deregulation give the buyer the right to nominate above the DCQ (eg., 110 percent or 125 percent of the DCQ) on any given day. Buyers use this right for different purposes. One purpose is to give the buyer the option to purchase limited quantities of peaking gas in order to meet unexpected demands (assuming transportation capacity is available) or to use the contract as a source of pipeline fuel gas. A more important purpose is to provide the buyer with a source of backup gas supply in the event that one of its other suppliers encounters deliverability difficulties.

Prior to deregulation when almost all gas was purchased from supply aggregators, few, if any, contracts gave the buyer the right to nominate above the DCQ. (Most of the contracts between producers and supply aggregators enable the aggregator to nominate at levels up to 125 percent of the DCQ, allowing aggregators to backstop one producer against another.)

Today, as LDCs increasingly act as their own supply aggregators, many are negotiating the right to nominate above the DCQ. This practice is particularly prevalent among central Canadian LDCs. The Consumers' Gas Cmpany Limited (Consumers' Gas) has the right to nominate up to 125 percent of the DCQ on its non-WGML gas contracts and Union Gas has the right to nominate 110 percent of the DCQ on most of its non-WGML supply arrangements. CWNG/NUL and Sask Energy, which have always acted as their own supply aggregators, have the right to nominate up to 125 percent or more of the DCQ on all their contracts with producers.

A small number of cogeneration contracts (6) also give the buyer the right to nominate above the DCQ largely as a measure of flexibility and a source of pipeline fuel.

3.3 Contract Balance

While the terms and conditions of a contract that bind or reinforce the buyer's and seller's commitments to purchase and deliver are important, also of significant importance is the balance between the seller's and the buyer's respective commitments. It is very difficult to assess fully either the buyer's or the seller's commitments in isolation from the other parties' obligations.

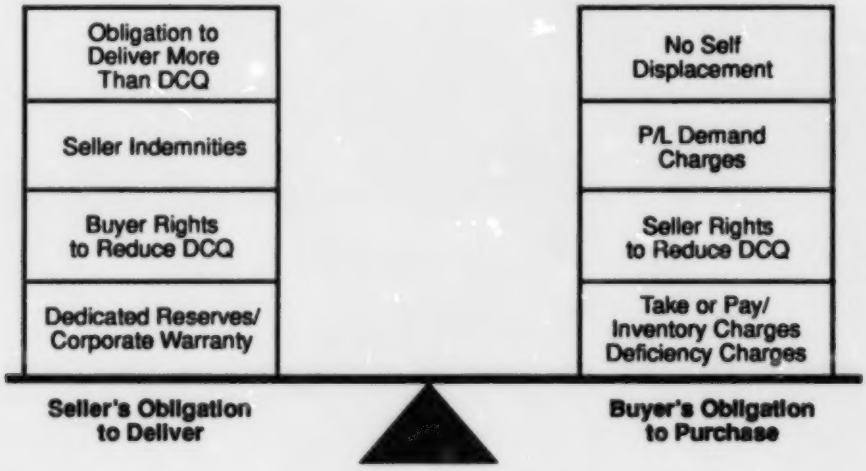
Figure 3-10 indicates that the possible combinations of different mechanisms that can be used by parties to secure the obligations to deliver and purchase is very large. Nevertheless, there are

standard combinations that are frequently used depending on the risks that are of foremost concern to the contracting parties.

For example, in contracts where the buyer has given the seller a take-or-pay commitment, it is common for the seller to either back its commitment to deliver with dedicated reserves or a corporate warranty. A survey of the contract inventory reveals that there are 18 contracts with take-or-pay obligations and dedicated reserves or corporate warranties. The average size of these contracts tends to be relatively small (9 MMcfd) and all are between producer/ marketers and cogeneration plants. There are a further 17 contracts where the buyers have supported their commitment to purchase with a GIC or equivalent and the sellers have backed their commitments with dedicated reserves or a corporate warranty. The average size of these contracts is much larger (55 MMcfd) and the contracts are typically between the major supply aggregators or the larger producer/marketers, and U.S. and Canadian LDCs and U.S. interstate pipelines.

Figure 3-10

Contract Balance


Obligation to Deliver More Than DCQ
Seller Indemnities
Buyer Rights to Reduce DCQ
Dedicated Reserves/ Corporate Warranty
No Self Displacement
P/L Demand Charges
Seller Rights to Reduce DCQ
Take or Pay/ Inventory Charges Deficiency Charges
Seller's Obligation to Deliver
Buyer's Obligation to Purchase

A large number of contracts (49) include dedicated reserves or corporate warranties, and the buyer's commitment to purchase is backed by a commitment not to self-displace, rather than take-or-pay, corporate warranties or a GIC. In 60 percent of these cases, the contracts are with central Canadian LDCs. Each of the central Canadian LDC contracts includes a commitment by the buyer not to self-displace. The remainder of these contracts are sales to U.S. cogenerators and U.S. LDCs.

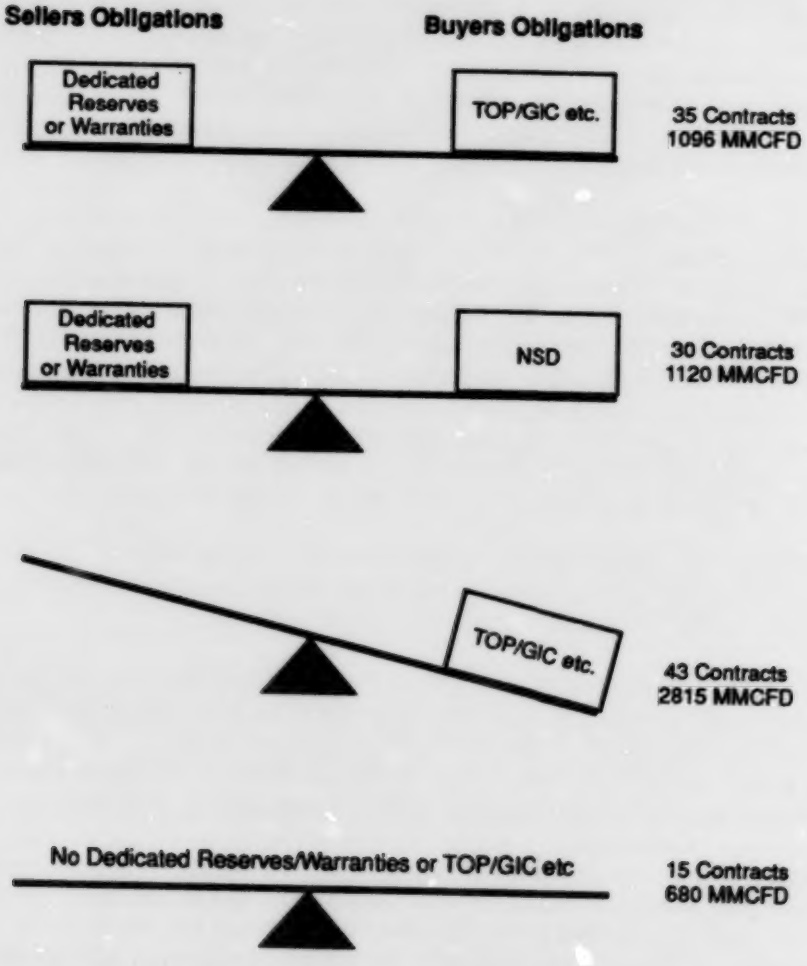
There is also a large number of contracts (43) that are not backed by dedicated reserves or corporate warranties but do include take-or-pay obligations. Many of these contracts were negotiated prior to deregulation and, in most cases, the threshold or trigger levels of the take-or-pay mechanisms have been renegotiated in recent years to lower levels.

Finally, there are a few contracts (15) that are balanced by the absence of any reinforced commitments to deliver or purchase such as take-or-pay, GICs, dedicated reserves or corporate warranties.

Figure 3 -11 summarizes some of the different forms of contract balance.

Figure 3-11

Contract Balance - Buyer/Seller Obligations



A second area of balance between the buyer's obligation to take and the seller's commitment to deliver is with respect to indemnities. As noted above, a large number of contracts negotiated since deregulation includes terms and conditions that indemnify the buyer against the incremental cost of replacement gas and any unabsorbed pipeline demand charges that may be incurred if the seller fails to deliver nominated volumes. To balance the seller's indemnities, almost all contracts in which the seller holds the transportation contract to the point of sale require the buyers to pay the full pipeline demand charge which in effect indemnifies the seller against any unabsorbed demand charges. Contracts that do not include demand charge obligations normally have a point of sale at the Alberta border and often state that the buyer must pay any unabsorbed demand charges on NOVA in the event that the buyer fails to nominate full contract quantities (eg., Union and Consumers' Gas contracts with non-WGML suppliers).

While none of the gas contracts surveyed includes terms under which the buyer has explicitly indemnified the seller against any incremental loss of revenue resulting from the buyer's failure to nominate the full contract quantities, terms and conditions such as take-or-pay compensate the seller at least up to a threshold level, and deficiency charges and GICs compensate part or all of any loss in revenue that the seller may experience as a result of sales of unnominated gas to third parties. These mechanisms, as noted above, typically "kick in" only when nominations drop below 60 - 70 percent of the DCQ, which leaves sellers potentially exposed to some revenue loss if they are unable to sell unnominated volumes to third parties at prices equivalent to the contract price.

A survey of the contracts indicates that most agreements negotiated since deregulation are well balanced between the buyer's and seller's respective indemnifications against costs or revenue loss up to 60 - 80 percent of the ACQ. For the last 20 - 40 percent of the ACQ, which is arguably the increment at greatest risk, the contract balance would appear to shift in favour of the buyer. This phenomenon is best explained by the relative strength of the buyer in today's over-supplied gas market. In contrast, contracts negotiated in the late 1970's and early 1980's when there were perceived shortages of gas supply, did not include seller indemnities. On the other hand, in most cases buyers during this period indemnified sellers against the cost of unnominated volumes through high take-or-pay provisions and pipeline demand charge obligations.

The last area in which contract balance is important is with respect to the terms and conditions that enable the buyer and seller to release volumes and pipeline capacity from the contract in the event that either party fails to meet a minimum level of performance.

As discussed earlier, a significant number (59) of the long-term contracts in the survey give the seller the right to permanently reduce contract quantities if the buyer fails to purchase minimum contract quantities (typically 60 - 80 percent of the ACQ) over an extended period of time (usually one to two years). At the same time, a large number of contracts (70) give the buyer the right to reduce contract quantities if the seller fails to deliver a specified level of nominated quantities.

A large proportion (50 percent) of the 129 contracts is balanced in that both the buyer and the seller have the right to reduce contract quantities in the event of a failure to achieve a minimum level of performance by the other party. The remaining contracts are biased in favour of either the buyer or seller. Of these, the largest number (44 contracts governing 1,170 MMcfd) is biased in favour of buyers to the extent that the buyer has a right to reduce contract volumes but the

seller has no corresponding right. A smaller number of contracts (21 contracts - 354 MMcfd) favour the seller as the only party who has a right to alter contract quantities.

A large number of contracts (40), many of which were executed prior to deregulation, provide no rights to either the buyer or seller to alter contract quantities.

3.4 Long-Term Contract Prices

Buyers and sellers use long-term contracts to secure a reliable market outlet for gas production (sellers) as well as a reliable supply for gas requirements (buyers). However, in only a few instances have buyers and sellers used long-term contracts as a vehicle to fix the price of natural gas for the term of the agreement.

Given the uncertainty over natural gas prices in the long term, most contracts adjust the price regularly (usually monthly) either on the basis of a pricing index specified in the contract or through periodic negotiations between the buyer and seller (in the latter circumstance, prices are normally adjusted annually). Unlike spot and short-term sales contracts which have standardized terms and conditions, and uniform prices determined through the competitive interaction of a large number of buyers and sellers, long-term contracts are typically unique and the pricing terms are determined by the parties to the contract.

The key considerations for buyers and sellers when negotiating the pricing terms of a long-term contract are: i) the point of sale; ii) the allocation of risks such as changes in pipeline tolls and exchange rate fluctuations (in the case of export contracts); iii) wellhead or field prices of western Canadian natural gas (i.e., the seller's alternatives or costs); iv) the price of alternative energy sources, particularly other sources of gas in the buyer's market region (i.e., the buyer's alternatives or costs); and v) the overall balance between the buyer's and seller's obligations to purchase and deliver.

Contract prices are normally the sum of a Demand Charge and a Commodity Charge.

3.4.1 Demand Charges

Most (80 percent) long-term contracts have a demand/commodity price structure. The demand charge is normally designed to recover from the buyer fixed costs that must be incurred regardless of actual gas flows. A demand charge component may include pipeline demand charges (eg., NOVA, TransCanada) incurred by the seller to the point of delivery' gas inventory charges and reservation fees; and administration fees. Less frequently they may also include the cost of pipeline fuel and pipeline commodity charges.

The further the point of sale is from the point of production, the more significant the demand charge becomes. All contracts in which the point of sale is downstream of the Alberta/B.C. or Alberta/Saskatchewan border have demand charge obligations. Many (34) contracts in which the point of sale is at the fieldgate or the Alberta border do not have demand charge obligations.

Most contracts do not allow demand charges to be renegotiated.

3.4.2 Commodity Charges

The commodity charge reflects the price of the natural gas actually sold under the contract and is either renegotiated periodically or is based on a pricing formula.

Contract commodity charges can be grouped into one of three categories: 1) market value contracts in which the commodity charge is based on the price of alternative energy sources in the buyer's market region (i.e., the buyer's alternative or avoided cost); 2) supply cost contracts where the commodity charge is based on the prices realized on other western Canadian gas; and 3) contracts in which the buyer and seller either through a formula or negotiation agree on a balance between the market value and the supply cost (Figure 3-12).

More than 90 percent of all export contracts have commodity charges that are based on market value. An important trend that has emerged in contracts since deregulation is that almost all market value charges are determined on a netback basis, that is, all or part of the transportation costs represented by the demand charges are deducted from the market value to determine the commodity charges.

Netting back demand charges shifts the risk of increases in pipeline tolls (or the benefits of declining tolls) to the seller. (This type of contract is often referred to as a netback agreement.)

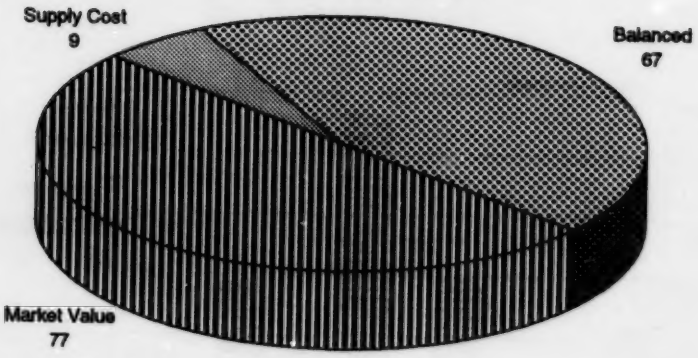
In contracts which existed immediately prior to deregulation, with the exception of one or two agreements (eg., WGML/Boundary Gas, Inc.), commodity charges on market value contracts are determined independently of demand charges as follows:

All domestic contracts fall into the third pricing category along with 7-8 percent of the export contracts. In almost all these cases the price is determined through negotiation rather than a formula or index. The objective of the negotiations is to determine a price which falls between the supply cost and the market value. It is difficult to state unequivocally in these cases whether the buyer or seller bears the risk of changing pipeline tolls and other fixed costs. It will depend on the negotiating strength of the respective parties and the nature of the market at the time prices are being determined (i.e., whether it is a seller's market or a buyer's market).

There are nine contracts in the survey in which the commodity price is determined on the basis of the supply cost only. In each of these cases, the risk of increases in pipeline tolls is borne by the buyer.

Figure 3 - 12

Contract Commodity Charges of Long - Term Canadian Gas Contracts Number of Contracts



3.4.3 Indexed vs. Negotiated Contract Prices

As noted above, very few contracts have fixed prices for the full term of the agreement. Prices are redetermined from time to time either through an indexing mechanism or negotiation (Figure 3-13). Almost all long-term export contracts have indexed pricing provisions. In contrast, the contract price of virtually all long-term contracts supplying the B.C., Alberta, Saskatchewan and central Canadian markets are renegotiated from time to time.

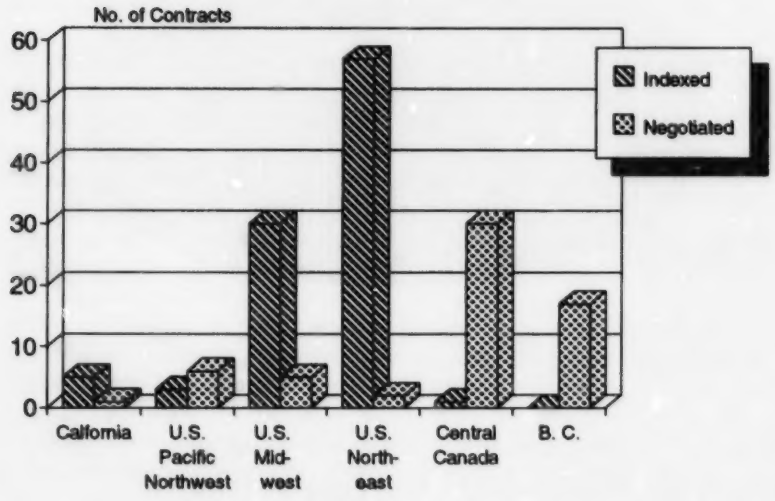
While the trend is clearly towards indexed prices, indices can only work effectively in circumstances where the prices of alternative fuels, including alternate sources of gas, are publicly available. In the U.S., there are large competitive regional markets for oil products (eg., New York harbour and the Gulf Coast) against which to index gas prices. There are regional oil product markets in Canada as well, but they are relatively thin, i.e., in some periods there may be insufficient trades to confidently determine a competitive price.

Many U.S. purchasers of Canadian gas have ready access to U.S. sources of natural gas and are often willing to index the commodity price of Canadian gas supplies to the price of U.S. gas sold under similar terms and conditions. In these circumstances, the price is determined on the basis of market value or avoided costs. In other words, the buyer is prepared to pay the same price for Canadian gas landed at its city gate as it must pay for U.S. gas supplies and in some cases for oil products on an energy equivalent basis.

To date, Canadian purchasers have not had meaningful access to alternative sources of gas against which to index the price of their supplies of western Canadian gas.

Figure 3 - 13

Long - Term Canadian Gas Contracts
Indexed vs Negotiated Pricing Terms
By Market Regions



Contracts that do not have a pricing formula usually provide an opportunity for the buyer and seller to renegotiate the price annually. These contracts often specify the principles or the objectives of the negotiations. For example, a contract may state that the objective is to establish a price that is competitive with the prices of other gas sold under contracts with similar terms and conditions in the buyer's market (market value) and in western Canada (supply cost).

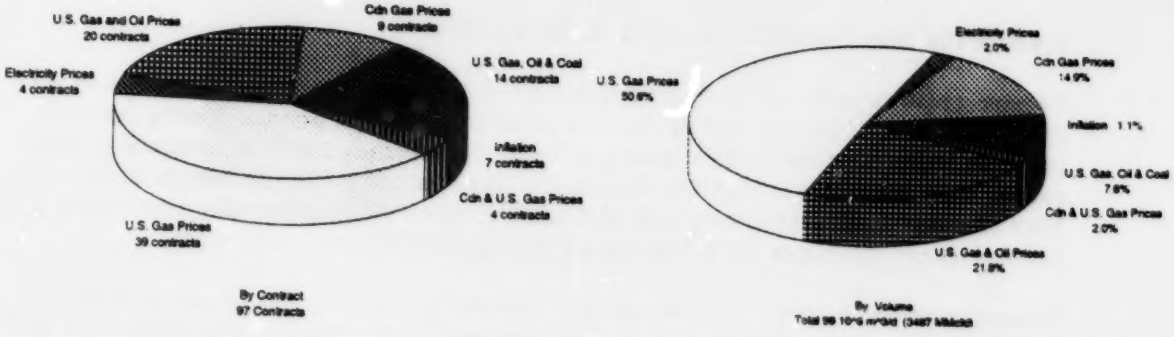
3.4.4 Key Drivers in Pricing Indices

As noted above, the determining factors in a pricing mechanism fall into one of three categories. They may be factors reflective of market conditions in the buyer's market, i.e., the cost of the buyer's alternative sources of energy (i.e., market value or avoided costs), such as U.S. sources of natural gas and oil products. Secondly, they may be factors reflective of conditions in the seller's market (i.e., the seller's supply cost), such as the Alberta Market Price (AMP) or thirdly, the price may be a balance between market value and supply cost (Figure 3-14).

Until recently, the trend among indexed contracts has been to base a pricing index on conditions in the buyer's market area. However, in the last eighteen months, a small number of export contracts (13) have been written in which the price is indexed to factors in either both the buyer's and seller's market regions or to conditions in the seller's market alone (i.e., Alberta gas prices).

Figure 3 - 14

Long - Term Canadian Gas Contracts With Price Indices By Type of Indices



Ninety percent of export contracts are indexed to factors in the buyer's market. The trend is to index LDC and interstate pipeline contract prices to the buyers' weighted average cost of gas (WACOG) which may only include long-term gas or in other cases includes both long and short-term gas. A small number of export contracts (14) link the price to a basket of fuels that includes gas, oil products and coal. All the contracts that have oil products in the pricing basket are with LDCs and cogeneration plants located in the U.S. Northeast, and LDCs located in the U.S. Pacific Northwest. Four cogeneration contracts partially link the pricing terms at least to a limited extent to the price received for the electrical output, enabling the seller to participate in the profits of the plant. Contracts that have coal prices in the index basket are to a small number of cogenerators (14) in the U.S. Northeast and U.S. Midwest. Several indexed contracts have a summer and winter step in the pricing formula so that the contract remains competitively priced during seasonal fluctuations which reduces the risk of either the buyer or the seller "shopping the market" for more attractive prices.

As noted earlier, a small number (11) of cogeneration contracts have fixed prices for the term of the agreement. Some (4) of these contracts are lump sum agreements in which the buyer pays royalties and an operating fee based on actual costs. Other contracts have a fixed unit charge that may be indexed to inflation or simply increased by a fixed rate (eg., 3 percent) per annum for the life of the agreement.

The structure of pricing formulae takes many different forms depending upon whether the contract is a netback agreement, the type and number of price drivers in the contract and the relative strength of the buyer and seller in the initial negotiations. Some of the contracts negotiated following natural gas deregulation include very complicated pricing indices that contain several factors. More recently, there has been a trend towards simpler and more easily administered pricing formulae.

3.4.5 Pricing Flexibility and Arbitration

To protect both the seller and the buyer against the risk that the pricing formula or index does not reflect the pricing objectives over the full term of the contract, most contracts specify that either party can request that the formula be renegotiated. To ensure good faith negotiations by both parties, many contracts allow pricing disputes that may arise to be resolved through arbitration. Most contracts limit renegotiation and arbitration to resolution of commodity price disputes. Demand charge obligations are not normally subject to renegotiation or arbitration.

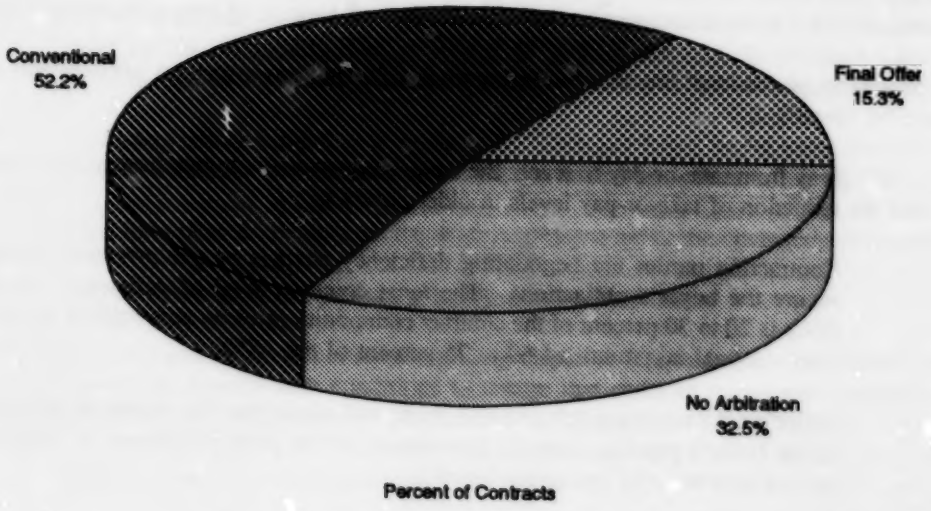
Domestic contracts in which prices are adjusted from time to time through negotiation all provide for disputes to be settled through arbitration. In the case of export contracts, if an agreement does not allow disputes to be referred to arbitration and a pricing issue can not be resolved, the status quo would normally prevail. In a few instances (eg., Amoco/NSP), if the dispute can not be resolved, the contract terminates.

Since deregulation, the trend has been to specify detailed criteria and objectives in the contract against which arbitrators must determine a price. Also, today's contract will often specify the rules of arbitration to be followed and the location. For example, many gas contracts for sale of gas into U.S. and Canadian markets specify that, in the event of arbitration, the proceedings will occur at the B.C. Centre for International Arbitration in Vancouver. In the case of contracts written under the law of Alberta, most parties have elected to substitute their own objectives and criteria rather than rely on the terms of the Alberta Arbitration Act.

Most contracts provide for conventional arbitration in which both parties present their position regarding prices before the arbitrators supported by evidence, and the arbitrator(s) establish a price based on the evidence presented, and the objectives and criteria stated in the contract (Figure 3-15). A more recent trend in gas contracts is to specify final offer or "baseball" arbitration. Under final offer arbitration, each party puts forward its price supported by evidence and the arbitrators must choose one or the other party's price. Final offer arbitration is common in contracts serving the B.C. and U.S. Pacific Northwest markets. It is also found in a small number of contracts to supply the U.S. Midwest.

Figure 3 - 15

Long - Term Canadian Gas Contracts With Price Arbitration



3.4.6 Relationship between Contract Price, and Buyer and Seller Obligations

Unlike spot gas sales, most long-term contracts explicitly recognize commitments by the buyer to purchase and seller to deliver in the pricing mechanism. For instance, in circumstances where the seller commits to contract for transportation to move the gas to the delivery point, the cost of transportation is often recognized in the pricing formula through the demand charge. Contracts with GICs or equivalent in effect also recognize costs that the seller may incur by committing to serve the buyer on a long-term basis.

Many export contracts recognize transportation costs that the buyer must incur. These costs may be accounted for directly through netback mechanisms or more commonly, implicitly, through a discount mechanism. For example, a contract may specify that the commodity price at the export point is 80 percent of a price index such as the buyer's WACOG. The 20 percent discount would be considered a proxy for the cost of transportation from the point of sale to the buyer's franchise area.

Theoretically, a long-term contract price should reflect the competitive market price for natural gas (eg., the spot or short-term, firm price) adjusted for differences in delivery points and any imbalances in the buyer's obligations to purchase and the seller's obligations to deliver. However,

in practical terms, the cost or value of any imbalances to the buyer and seller are highly subjective depending on current market conditions and the perception of risk by the parties to each contract. As a result, the prices on similar contracts can vary widely.

3.5 Summary

In recent years as the structure of long-term gas contracts has changed, there have been important new trends in the detailed terms and conditions and overall balance of long-term gas agreements.

The following are the most important trends in terms of conditions of natural gas contracts which have been identified:

1. A shift away from take-or-pay to secure the buyer's commitment to purchase in new contracts and the reduction of take-or-pay levels in older contracts.

    - Contracting parties are negotiating deficiency charges or gas inventory charges to secure the buyer's obligations. The most common level of deficiency charges or GICs is 20 to 30 percent of the contract commodity price on unit volume deficiencies below annual minimums of 60 to 75 percent of the ACQ.

    - Seller's risks are being reduced with terms and conditions that assure the seller access to the buyer's pipeline capacity downstream of the point of delivery to facilitate the sale of unnominated gas to third parties.

2. Buyer commitments not to self-displace. These commitments first emerged in contracts with central Canadian LDCs. NSD clauses are effective in preventing the buyer from "shopping the market" for the lowest priced gas.

    - Contracts commonly include the right for the seller to reduce contract quantities (particularly if the gas is for resale), if the buyer fails to meet a specified level of performance measured by the annual load factor or trigger quantity. The purpose of this right is to protect the seller against the risk that the buyer permanently loses its market for the gas.

    - Many buyers who act as demand aggregators (i.e. purchase for resale) have negotiated the right to reduce contract quantities if their sales are displaced by other natural gas. Such Operational Demand Volume adjustment clauses are universal in central Canadian LDC contracts and they are emerging in contracts to serve other market regions.

3. The use of dedicated reserves and corporate warranties to secure the seller's obligation to deliver contract quantities.

    - Widespread use of seller indemnities to the buyer against specific costs in the event that the seller fails to deliver nominated quantities.

- Buyer rights to reduce contract quantities if the seller fails to meet a minimum level of performance.

4. Establishment of a balance between the buyer's and seller's commitments and obligations.

5. Contract prices are normally renegotiated annually or the price is indexed to various market indicators and adjusted monthly. Very few long-term contracts have a fixed price for the term of the contract.

   - Export contracts have been established with a price based on market value by indexing the commodity price or charge to an indicator of U.S. gas prices such as LDC WACOGs and netting out transportation costs. (i.e. netback agreements).

   - Increasing use of indicators of western Canadian gas prices in the index (which also provide a balance between the buyer's and seller's alternatives).

   - Most long-term domestic contracts have negotiated rather than indexed pricing terms.

   - Indices that include oil product prices are less widely used.

6. Arbitration terms and conditions to resolve pricing disputes. Approximately two-thirds of the contracts surveyed contain such conditions to ensure that contract prices remain consistent with the objectives of the agreement over the full contract term.

   - Most contracts rely on conventional arbitration.

   - A number of contracts have specified final offer or "baseball" arbitration over the last two years.

Chapter 4
Summary And Conclusions

Prior to 1985, the year in which deregulation of the natural gas industry began in Canada and the U.S., effectively all western Canadian natural gas was sold under long-term contracts. There were only a small number of buyers and sellers and the format and structure of long-term contracts remained unchanged for almost three decades. These contracts were the foundation for much of the financing required to build the Canadian natural gas industry.

Since the mid 1980's several fundamental changes have occurred to the long-term contracting regime governing the sale of Canadian natural gas. The impetus for this change has been the deregulation of natural gas prices and markets in Canada and the U.S., which created the opportunity for a large number of new buyers and sellers to enter the market. Additional factors that have influenced contracting practices since deregulation have been the emergence of the Northeast U.S. as a major new market region for Canadian gas requiring large investments in Canadian and U.S. pipeline facilities, and the development of cogeneration, also primarily in the U.S. Northeast, as an important new market sector for natural gas.

In many respects, the changes that have occurred since the mid 1980's will set the pattern for future contracting practices in the natural gas industry. The most important changes have been:

1) increased flexibility for both the buyer and the seller in long-term contracts, enabling the parties to respond more readily to changing demand and supply conditions. Many long-term agreements today provide the contracting parties with much of the same flexibility as short-term contracts while still giving the seller a secure long-term outlet for its gas supply and providing the buyer with a reliable and stable source of gas;

2) greater balance between the buyer's obligations to purchase and the seller's obligation to deliver, increasing the prospect of a successful and enduring business relationship, reducing the risk of contract disputes over the full term of the agreement;

3) flexible and increasingly simple contract pricing terms that track competitive market conditions, reducing the risk to both parties of contract prices that are "off market" for extended periods;

4) shorter contract terms that enable the parties to "adjust" sooner and more fully to unanticipated structural changes in the natural gas industry;

5) reduced contract volumes as smaller end-users and smaller producer/marketers enter the market and as larger buyers and sellers continue to diversify their supply portfolios and market outlets; diversified supply sources and markets increase the reliability of supply and the stability of market outlets; and

6) unbundling gas sales and transportation service providing both buyers and sellers with a wider range of contracting options and choices.

While long-term contracts governing the sale of western Canadian gas have changed significantly since deregulation, the changes and trends have not been uniform across all market areas, and important differences exist in the pattern of export contracts compared to domestic contracts.

4.1 Structure of Export vs. Domestic Contracts

The Alberta and Saskatchewan intra-provincial markets for natural gas have changed little since deregulation in 1985. The long-term contracts supplying these markets were not subject to federal price regulations[15] and the structure of these agreements has remained unchanged since the 1960's. The major local distribution companies not only act as demand aggregators, but they also act as their own supply aggregators. The major Alberta and Saskatchewan LDCs purchase most of their gas requirements directly from a large number of producer/marketers under relatively small volume contracts. (Sask Energy's major contracts with WGML terminated in late 1991.)

Since deregulation the trend in the structure of contracts to supply the other domestic market regions, British Columbia and central Canada, has been towards a structure similar to the Alberta/Saskatchewan contracts:

1) the B.C. and central Canadian LDCs now act as their own supply aggregators, purchasing their long-term gas requirements on a portfolio basis from a range of producer/marketers as well as the traditional aggregators. These contracts are also much smaller than the typical agreements that existed prior to deregulation,

2) the point of purchase on the LDC contracts has shifted upstream to the inlet of the major transmission systems. Today, the central Canadian LDCs purchase virtually all their long-term gas requirements at the Alberta/Saskatchewan border at the inlet to the TCPL pipeline system. BC Gas Inc. purchases its gas requirements at a variety of points on the Westcoast system, including the wellhead and the city gate; and

3) reliance on gas purchased under long-term contracts has declined. Western Canadian gas committed under long-term contracts to all three major domestic market regions has declined substantially since deregulation as a result of industrial, commercial and, more recently, the residential sector purchasing directly from producer/marketers under short-term (typically one to two year) gas contracts.

In contrast to the domestic markets:

1) U.S. demand aggregators (i.e., U.S. interstate pipelines and LDCs) in large part continue to purchase Canadian gas from supply aggregators, although increasingly U.S. demand aggregators, particularly U.S. LDCs, have recently elected to diversify their portfolio of Canadian gas (eg., Consumers Power Company, Northern Natural and NSP) through direct purchases with several producer/marketers. (In California, PG&E has always acted as its own supply aggregator through its subsidiary, A&S.)

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[15] Alberta gas sold in Saskatchewan was subject to federal price controls.

2) U.S. demand aggregators have not shifted the point of purchase of their Canadian gas on their long-term contracts upstream. U.S. LDCs and interstate pipelines continue in almost all cases to purchase Canadian gas at the export point on the Canada/U.S. border. There are noteworthy exceptions. For example, the recent agreement between NSP and Amoco in which the point of sale is the inlet to the TransCanada pipeline. NSP will hold the transportation contract on TransCanada. Other exceptions are the contracts between WGML and Northern Natural, and the Shell contracts with Enron Gas Marketing Inc. and Midwest Gas Company in which the Canadian seller (or its U.S. marketing affiliate) will transport the gas to the point of sale, Ventura, Iowa. Finally, PG&E, through its affiliate, A&S, purchases gas at the fieldgate.

As in the Canadian market, the volume of western Canadian gas committed under long-term contracts has declined in the U.S. Pacific Northwest and the U.S. Midwest and sales of short-term gas have increased dramatically (most short-term gas is sold on a spot rather than a firm basis to U.S. buyers). The exception has been the U.S. Northeast market where there has been a significant increase in long-term contracts to support the necessary pipeline construction to serve the region and to secure financing for cogeneration plants. To date, the volume of gas contracted on a long-term basis to the California market has remained relatively stable.

In the past, the only Canadian buyers of long-term gas have been the LDCs and, within Alberta, several industrial buyers. More recently, Canadian cogeneration plants have purchased gas under long-term agreements but these contracts are not in the public domain and are not included in this survey. U.S. purchasers of long-term Canadian gas include LDCs, interstate pipelines and cogeneration plants and, more recently, electric utilities.

4.2 Differences in Terms and Conditions between Export and Domestic Contracts

The terms and conditions of long-term contracts vary considerably, not only between market regions but also within market regions and it is difficult to make distinctions between the terms and conditions of export and domestic long-term contracts. Nevertheless, within specific domestic markets, there are noteworthy developments that can be contrasted with export agreements.

4.2.1 Buyer's Obligation to Purchase

Two important contract conditions have emerged since deregulation regarding the buyer's obligation to purchase.

1) The operational demand volume (ODV) adjustment mechanisms; almost all long-term agreements to supply domestic markets have an ODV adjustment clause. (CWNG/NUL contracts in Alberta have a "market out" provision which is similar to an ODV mechanism.) In contrast, only a small number of export contracts include similar mechanisms.

2) Commitments not to self-displace; within Canada, the buyers in the central Canadian market have backed their obligation to purchase with no self-displacement (NSD) commitments which reduce the risk of the buyer "shopping the market". (In the Alberta/Saskatchewan market region, the buyer's obligations are backed by high take-or-pay commitments.) Relatively few U.S. buyers have backed their purchase obligations with NSD clauses. While many export contracts have take-or-pay and deficiency charges, the threshold levels tend to be at relatively low levels, leaving the seller exposed to the risk that the buyer will "shop the market" for at least part of the contract volumes. To a limited extent, this risk is reduced if the seller has access to pipeline capacity and can sell unnominated gas on the spot market.

4.2.2 Seller's Obligation to Deliver

Under virtually all long-term contracts to supply gas to the three domestic market regions, the seller's obligations to deliver are backed either by dedicated reserves or corporate warranties. In the case of export contracts, a significant number of agreements are backed by dedicated reserves and warranties. However, there are also a large number of export contracts executed prior to and after deregulation that are not backed by either reserves or warranties. The largest proportion of these contracts are with supply aggregators in which the gas purchased by the aggregator from producers is backed by dedicated reserves.

4.2.3 Long-Term Contract Prices

There is an important distinction between the pricing provisions of export and domestic contracts. The prices of almost all domestic long-term contracts are renegotiated annually. (The few exceptions are indexed to the negotiated prices on other domestic contracts, eg., the WGML/Centra Manitoba Gas Inc. contract price is indexed to the Ontario LDC prices.) While a small number of export contracts require the price to be renegotiated annually (eg., A&S/PG&E), the largest proportion of export contracts have indexed pricing provisions. Contract prices are typically based on market value and indexed to the buyer's alternatives, usually the price of U.S. supplies of gas and, in a smaller number of cases, oil product prices.

All domestic contracts enable pricing disputes to be settled through either final offer or conventional arbitration. Approximately 50 percent of export contracts allow pricing disputes to be settled through arbitration. In the event of a dispute under contracts with no provision for arbitration, the status quo would normally prevail.

SURVEY OF LONG TERM NATURAL GAS CONTRACTS

(To December 31, 1991)

SELLER	BUYER	BUYER TYPE	CONTRACT ERA	TERM (Years)	CONTRACT QUANTITY (10^6 m^3 /d)	(MMcfd)
CENTRAL CANADA						
Shell I	Union Gas	LDC	Post	10	0.3	11.0
Shell II	Union Gas	LDC	Post	13	0.3	11.7
Shell	Consumers	LDC	Post	10	0.5	19.0
Cdn. Hunter	Union Gas	LDC	Post	11	0.5	19.4
Cdn. Hunter I	Consumers	LDC	Post	10	0.5	19.0
Cdn. Hunter II	Consumers	LDC	Post	10	0.5	19.0
Unigas I	Union Gas	LDC	Post	15	0.3	10.0
Unigas II	Union Gas	LDC	Post	15	0.3	11.0
Unigas III	Union Gas	LDC	Post	6.5	0.2	5.4
Direct Energy I	Consumers	LDC	Post	10	0.4	15.8
Direct Energy II	Consumers	LDC	Post	11	0.5	19.0
Direct Energy III	Consumers	LDC	Post	10	0.3	9.5
Western Gas	Union Gas	LDC	Post	12	2.1	74.0
Western Gas	Centra (Ont)	LDC	Post	15	3.3	118.0
Western Gas	Centra (Man)	LDC	Post	15	7.6	270.0
Western Gas	Consumers Gas	LDC	Post	15	8.6	305.0
Western Gas	Gaz Metro	LDC	Post	15	2.2	77.0
Gulf I	Union Gas	LDC	Post	10	0.3	11.0
Gulf II	Union Gas	LDC	Post	11	0.4	15.5
Gulf	Consumers	LDC	Post	10	0.4	13.3
SaskOil	Union Gas	LDC	Post	15	0.3	11.2
Northridge	Consumers	LDC	Post	10	0.2	5.7
Northridge	Union Gas	LDC	Post	9	0.4	15.0
Renaissance	Consumers	LDC	Post	10	0.3	9.5
Amerada	Union Gas	LDC	Post	7	0.1	3.7
Home Oil	Consumers	LDC	Post	10	0.5	18.4
Unocal	Consumers	LDC	Post	10	0.4	15.8
Northstar	Union Gas	LDC	Post	7	0.1	3.7
Petro Can I	Union Gas	LDC	Post	15	0.3	11.2
Petro Can II	Union Gas	LDC	Post	6	0.2	7.5
Pan Alberta	Gaz Metro	LDC	Pre	20	0.5	17.9
TOTAL CENTRAL CANADA					[illegible]	[illegible]

Contract Era indicates whether a contract was executed pre or post deregulation.

SURVEY OF LONG TERM NATURAL GAS CONTRACTS

(To December 31, 1991)

SELLER	BUYER	BUYER TYPE	CONTRACT ERA	TERM (Years)	CONTRACT QUANTITY (10^6 m^3 /d)	(MMcfd)
ALBERTA & SASKATCHEWAN						
368 Contracts	CWNG/NUL	LDC	Pre	20-25	13.4	472.0
109 Contracts	Sask Energy	LDC	Pre	20-25	6.6	233.0
TOTAL ALBERTA & SASKATCHEWAN					**20.0**	**705.0**
BRITISH COLUMBIA						
Czar Resources	BC Gas	LDC	Post	15	0.3	10.0
Cdn. Hunter (2)	BC Gas	LDC	Post	10	0.8	27.0
Penn West	BC Gas	LDC	Post	15	0.1	5.0
Shell	BC Gas	LDC	Post	15	0.3	10.0
Esso	BC Gas	LDC	Post	15	0.2	6.0
Amoco	BC Gas	LDC	Post	15	0.8	28.0
Unocal	BC Gas	LDC	Post	15	0.6	20.4
Columbia Gas	BC Gas	LDC	Post	15	0.4	13.2
Kerr-McGee	BC Gas	LDC	Post	15	0.1	4.0
BP Resources	BC Gas	LDC	Post	15	1.2	43.9
Amerada Hess (2)	BC Gas	LDC	Post	10	0.5	17.0
A&S	BC Gas	LDC	Post	10	2.0	70.0
Mobil	BC Gas	LDC	Post	10	0.3	10.0
NW Pacific	BC Gas	LDC	Post	10	0.7	25.0
CanWest	BC Gas	LDC	Post	15	4.0	140.0
Total Petro	BC Gas	LDC	Post	15	0.1	3.5
Petro Canada	BC Gas	LDC	Post	15	0.7	25.0
TOTAL BRITISH COLUMBIA					**13.0**	**451.0**
CALIFORNIA						
Shell	SoCal Edison	Elecuric Utiiity	Post	15	1.5	52.0
Western Gas	SoCal Edison		Post	15	1.5	52.3
Alberta Energy	SoCal Edison		Post	15	1.5	52.0
Esso Resources	SoCal Edison		Post	15	1.5	52.0
Pan Alberta	SoCal Gas	LDC	Pre	20	6.8	240.0
PG&E	A&S	LDC	Pre	20	22.0	775.0
TOTAL CALIFORNIA					**34.7**	**1,223.3**

SURVEY OF LONG TERM NATURAL GAS CONTRACTS

(To December 31, 1991)

SELLER	BUYER	BUYER TYPE	CONTRACT ERA	TERM (Years)	CONTRACT QUANTITY (10^6 m^3 /d)	(MMcfd)
U.S. MIDWEST						
Shell	Midland Cogen	Cogen	Post	15	0.4	15.0
North Cdn Oils	Midland Cogen	Cogen	Post	14	0.3	10.0
Western Gas	Midland Cogen	Cogen	Post	15	0.4	15.0
Canterra	Midland Cogen	Cogen	Post	15	0.4	15.0
North Cdn Oils	Midland Cogen	Cogen	Post	15	0.2	7.0
Norcen	Midland Cogen	Cogen	Post	12	0.2	6.5
Poco	Midland Cogen	Cogen	Post	15	0.4	15.0
Progas	ANR	Interstate P/L	Pre	20	2.1	75.0
Unigas	N. Natural	Interstate P/L	Post	12	2.8	100.0
Western Gas	N. Natural I	Interstate P/L	Post	10	1.3	47.5
Western Gas	N. Natural II	Interstate P/L	Post	10	0.7	25.0
Western Gas	N. Natural III	Interstate P/L	Post	6	1.4	50.0
ProGas	Nat. Gas Pipe	Interstate P/L	Pre	20	2.1	75.0
Pan Alberta	N. Natural I	Interstate P/L	Pre	20	5.7	200.0
Pan Alberta	N. Natural II	Interstate P/L	Post	10	2.8	100.0
Pan Alberta	Panhandle	Interstate P/L	Pre	20	4.2	150.0
Western Gas	Nat. Gas Pipe	Interstate P/L	Pre	40	4.9	171.3
ProGas	Tennessee	Interstate P/L	Pre	20	2.1	75.0
Mobil	N. Natural	Interstate P/L	Post	10	0.6	20.0
Shell	Enron	Interstate P/L	Post	15	0.3	9.8
Norcen	Consumers Power	LDC	Post	15	0.4	15.0
Shell	Consumers Power	LDC	Post	6	0.4	15.0
Shell	Midwest Gas	LDC	Post	15	0.6	20.5
Amoco	NSP-W	LDC	Post	10	0.4	15.0
Amoco	NSP	LDC	Post	13	0.4	15.0
Western Gas	Consumers Power	LDC	Post	15	0.4	15.0
Western Gas	NMU I	LDC	Post	10	0.3	10.0
Western Gas	NMU II	LDC	Post	10	0.9	31.4
Western Gas	SE Migas	LDC	Post	15	0.4	15.0
Western Gas	Minnegasco	LDC	Post	10	1.4	50.0
Cdn. Montana	Cdn. Montana	LDC	Pre	30	0.8	27.4
ProGas	NSP-W	LDC	Post	10	0.2	7.5
Poco	Consumers Power	LDC	Post	15	0.4	15.0
North Cdn Oils	Consumers Power	LDC	Post	15	0.3	10.0
Canterra	Consumers Power	LDC	Post	15	0.4	15.0
Cdn. Oxy	NSP	LDC	Post	10	0.2	7.5
TOTAL U.S. MIDWEST					[illegible]	[illegible]

SURVEY OF LONG TERM NATURAL GAS CONTRACTS

(To December 31, 1991)

SELLER	BUYER	BUYER TYPE	CONTRACT ERA	TERM	CONTRACT QUANTITY	
				(Years)	(10^6 m^3 /d)	(MMcfd)
U.S. NORTHEAST						
Western Gas	Ocean State	Cogen	Post	20	0.7	25.0
Western Gas	Megan Racine	Cogen	Post	15	0.3	11.7
Western Gas	FSC I	Cogen	Post	15	1.5	54.0
Western Gas	FSC II	Cogen	Post	15	0.5	16.0
ProGas	Northeast Energy	Cogen	Post	15	1.0	36.0
ProGas	OSP I	Cogen	Post	20	1.4	50.0
ProGas	OSP II	Cogen	Post	20	0.7	25.0
ProGas	N. Jersey Energy	Cogen	Post	15	1.0	36.0
ProGas	Lockport	Cogen	Post	15	0.3	12.0
ProGas	MASSPOWER	Cogen	Post	15	0.7	25.0
Star	Fulton	Cogen	Post	14	0.2	6.0
OMV	Fulton	Cogen	Post	14	0.2	6.5
Devnic	Indeck-C	Cogen	Post	15	0.2	8.0
Northstar	Indeck-C	Cogen	Post	15	0.1	2.5
Universal et al.	Indeck-C	Cogen	Post	15	0.2	7.0
Morgan	L&J	Cogen	Post	15	0.3	11.7
Trilogy	Indeck Ilion	Cogen	Post	18	0.2	8.0
Sceptre	Encogen	Cogen	Post	15	0.4	14.8
Husky	Power City	Cogen	Post	15	0.6	20.0
Columbia	Pawtucket	Cogen	Post	20	0.2	6.4
Opinac	Pawtucket	Cogen	Post	20	0.2	6.4
Cdn. Oxy	LILCO	Cogen	Post	15	0.4	15.3
Paramount	JMC Selkirk	Cogen	Post	15	0.7	23.0
Bow Valley	Indeck Yerkes	Cogen	Post	15	0.2	6.0
Northstar	Indeck Yerkes	Cogen	Post	15	0.2	6.0
Inverness	Indeck Oswego	Cogen	Post	15	0.0	1.0
Chesapeake	Indeck Oswego	Cogen	Post	15	0.0	1.0
Universal	Indeck Oswego	Cogen	Post	15	0.1	4.0
Northstar	Indeck Oswego	Cogen	Post	15	0.0	1.0
Bow Valley	Indeck Oswego	Cogen	Post	15	0.2	5.7
Ramarro	EME	Cogen	Post	15	0.2	6.0
Vector	APLP	Cogen	Post	15	1.0	36.5
North Cdn Oils	E. Georgia	Cogen	Post	20	0.2	6.8

SURVEY OF LONG TERM NATURAL GAS CONTRACTS

(To December 31, 1991)

SELLER	BUYER	BUYER TYPE	CONTRACT ERA	TERM (Years)	CONTRACT QUANTITY (10^6 m^3 /d)	(MMcfd)
U.S. NORTHEAST (Continued)						
Canstates	TEMCO	Cogen	Post	15	1.4	48.4
Brymore	Dartmouth	Cogen	Post	20	0.5	16.0
Renaissance	Kamine-Carth.	Cogen	Post	15	0.4	14.2
Renaissance	Kamine-S. Glen	Cogen	Post	15	0.4	14.2
Renaissance	NE Power	Cogen	Post	20	0.4	15.0
Triton	NE Power	Cogen	Post	20	0.4	15.0
BP Resources	NE Power	Cogen	Post	20	0.3	10.0
Sceptre	NE Power	Cogen	Post	20	0.6	20.0
Pan Canadian	Selkirk	Cogen	Post	15	0.5	19.0
Esso	Selkirk	Cogen	Post	15	0.5	19.0
ATCOR	Selkirk	Cogen	Post	15	0.5	17.0
Cdn. Hunter	GAS Systems	Cogen	Post	20	0.8	30.0
Shell	CETI	Cogen	Post	20	0.4	14.0
Western Gas	Tennessee	Interstate P/L	Pre	14	0.6	20.3
ProGas	TETCO	Interstate P/L	Pre	20	2.1	75.0
Esso	Transco	Interstate P/L	Pre	15	2.1	75.0
Kanngaz	Tennessee	Interstate P/L	Pre	20	2.3	79.9
Alberta Energy	Alberta NE	LDC	Post	15	0.5	17.5
ProGas	Alberta NE	LDC	Post	15	1.9	66.0
ATCOR	Alberta NE	LDC	Post	15	1.0	35.0
Western Gas	Alberta NE	LDC	Post	15	7.8	275.0
Western Gas	Vermont Gas	LDC	Post	20	0.9	32.0
Western Gas	Niagara Gas	LDC	Pre	30	0.9	32.0
Western Gas	Niagara Mohawk	LDC	Post	15	1.4	51.0
Western Gas	Elizabethtown	LDC	Post	15	0.3	10.0
Western Gas	Boundary Gas	LDC	Pre	15	2.6	92.5
Shell	Granite States	LDC	Post	10	0.7	25.0
Amoco	Con. Edison	LDC	Post	15	0.8	30.0
Unigas	Rochester G&E	LDC	Post	10	0.5	16.0
Esso	Boston Gas	LDC	Post	15	1.0	35.0
TOTAL U.S. NORTHEAST					**48.7**	**1,719.3**

SURVEY OF LONG TERM NATURAL GAS CONTRACTS

(To December 31, 1991)

SELLER	BUYER	BUYER TYPE	CONTRACT ERA	TERM	CONTRACT QUANTITY	
				(Years)	(10^6 m^3 /d)	(MMcfd)
U.S. PACIFIC NORTHWEST						
Amoco	NW Natural	LDC	Post	15	0.2	8.0
Summit	NW Natural	LDC	Post	7	0.2	8.0
CanWest	NW Natural	LDC	Post	15	2.6	92.0
Poco	NW Natural	LDC	Post	10	0.4	15.7
Poco	IGI Resources	LDC	Post	9	0.6	20.0
Mobil	IGI Resources	LDC	Post	10	0.4	12.5
Mobil	Cascade	LDC	Post	10	0.3	11.6
Mobil	Wash. Natural	LDC	Post	10	0.3	9.6
Amoco	Wash. Natural	LDC	Post	15	0.7	24.0
Poco	Wash. Natural	LDC	Post	10	0.4	15.0
Pan Canadian	Wash. Water	LDC	Post	15	0.6	20.0
Alberta Energy	Wash. Water	LDC	Post	15	0.6	20.0
Unocal	Wash. Water	LDC	Post	15	0.6	20.0
TOTAL U.S. PACIFIC NW					7.8	276.4

APPENDIX B

List of Abbreviations

A&S	Alberta and Southern Gas Co. Ltd.
ACQ	Annual Contract Quantity
AMOCO	Amoco Canada Petroleum Company Ltd.
ANE	Alberta Northeast Gas, Limited
ATQ	Annual Trigger Quantity
B.C.	British Columbia
BC Gas	BC Gas Inc.
B.C.P.C.	British Columbia Petroleum Corporation
CanWest	CanWest Gas Supply Inc.
Consumers' Gas	Consumers' Gas Company Limited, The
CWNG	Canadian Western Natural Gas Company Limited
DCQ	Daily Contract Quantity
FERC	Federal Energy Regulatory Commission
Foothills	Foothills Pipe Line Ltd.
GIC	Gas Inventory Charge
GMi	Gaz Métropolitain, inc.
LDC	Local Distribution Company
Mcfd	million cubic feet per day
MCQ	Monthly Contract Quantity
Mobil	Mobil Oil Canada
MW	Megawatts
NEB	National Energy Board

NEPC	New England Power Company
Northern Natural	Northern Natural Gas Company
Northridge	Northridge Petroleum Marketing, Inc.
Northstar	Northstar Energy Corporation
Northwest Pipe	Northwest Pipeline Corporation
NOVA	NOVA Corporation of Alberta
NSD	No Self-displacement
NSP	Northern States Power Company
NUL	Northwestern Utilities Limited
ODV	Operating Demand Volume
Pan-Alberta	Pan-Alberta Gas Ltd.
PG&E	Pacific Gas and Electric Company
PGT	Pacific Gas Transmission Company
PITCO	Pacific Interstate Transmission Company
Poco	Poco Petroleums Ltd.
ProGas	ProGas Limited
Sask Energy	Saskatchewan Energy
Shell	Shell Canada Limited
Socal	Southern California Gas Company
SoCal Edison	Southern California Power Company
SOQUIP	Société Québécoise d'Initiatives Pétrolières
TransCanada	TransCanada PipeLines Limited
Unigas	Unigas Corporation
Union Gas	Union Gas Limited

U.S.	United States of America
WACOG	Weight Average Cost of Gas
Westcoast	Westcoast Energy Inc.
WGML	Western Gas Marketing Limited
10^6m^3/day	million cubic metres per day

APPENDIX C

Glossary

Annual Contract Quantity — The daily contract quantity times the number of days in the year.

As-Billed — The methodology in natural gas pipeline rate design in which all charges that the pipeline pays for natural gas supplies and transportation that are passed through to its customers in the same form, demand or commodity, by which those costs were charged to the pipeline. In 1986, FERC's Opinion 256 determined that charges for imported natural gas should not be passed through on an "as-billed" basis because the FERC had not had an opportunity to review the form of those charges to determine whether they were consistent with the form of charges for domestic natural gas supplies; i.e., that they are cost-based and do not include any production and gathering fixed costs in a demand charge.

Back-Stopped Supply — A service whereby backup gas is provided in the event that a customer's gas fails to be delivered to the distributor.

Broker — An individual or independent corporation engaged in bringing together sellers and buyers of natural gas, usually on a short-term firm or spot basis, assisting in negotiations, and arranging transportation and delivery terms. Brokers usually do not buy or sell for their own account, but act as agent for the buyer and/or seller. A major function of some marketing transactions is the aggregation of natural gas suppliers and/or purchasers.

Bundled Rate — A single charge that covers a number of services provided by a pipeline or distributor. Examples of such services are gas sales, transportation, storage and load-balancing.

Buy/Sell — In this arrangement, the end-user purchases its own supply of gas and arranges for transportation, generally to the distributor's delivery point. The distributor purchases the gas and commingles it with the balance of its supplies, and then sells gas to the end-user as a sales customer under the appropriate rate schedule.

Capacity Brokering — The selling or renting by a shipper of its contracted pipeline capacity to others.

Capacity, Peaking — The capacity of facilities or equipment normally used to supply incremental natural gas under extreme demand conditions.

Peaking capacity is generally only available for a limited number of days at a maximum rate.

City Gate — The delivery point or the point of interconnection between inter-provincial and interstate pipelines (eg. TransCanada) and local distribution companies (eg., Gaz Métropolitain inc.).

Cogeneration — The use of a fuel source in a reciprocating engine or gas turbine to generate both electrical and thermal energy to optimize fuel efficiency. The dominant demand for energy may be either electrical or thermal.

Commercial Sector — That portion of the natural gas market consisting of businesses and institutions, including federal, state and local government agencies, agriculture, the service sector (e.g., wholesale and retail trade, hotels, restaurants, hospitals and schools) and apartment buildings.

Commodity Charge — A charge payable by a gas purchaser in a sales contract for each unit of gas purchased. The unit charge generally covers the commodity component of any applicable pipeline tolls and the cost of gas. Compare Demand Charge.

Contract Demand — The amount of natural gas a seller agrees to deliver on a periodic (daily, monthly, annually) basis in accordance with a gas purchase agreement. Contract demand is a maximum amount.

Contract Term — The term of effectiveness of a contract. It may not be possible to determine accurately from the contract language what will be the actual effective term of the contract, unless specific dates are set out. Many contracts state (1) that the term begins from the date of initial production or delivery, (2) that the contract may be extended from month to month or year to year until notice of termination is given, or (3) that the contract will remain in effect for the life of the lease or until the dedicated reserves are depleted.

Contract Year — Typically 1 November to the following 31 October.

Contracted Reserves — Natural gas reserves dedicated to fulfil natural gas purchase agreements.

Core Market — Generally that part of the gas market that does not possess fuel switching capability in the near term; typically, residential, commercial and small industrial users.

Deficiency Charge — A charge per unit of deficiency imposed when a buyer's actual purchases fall below a required minimum or threshold level, as under reservation fees and gas inventory charges.

Deliverability — The amount of natural gas a well, field, pipeline, or distribution system can supply in a given period of time. Also, the practical output from a storage reservoir.

Delivery Point — The point on a pipeline's system at which it delivers natural gas that it has transported.

Demand Charge — A fixed, usually monthly obligation of a gas purchaser in a sales contract. It may cover some or all of a seller's fixed costs and is payable regardless of volumes actually taken. Compare Commodity Charge.

Development Contract — A development contract differs from a conventional gas purchase contract in that not all reserves are established at the time it is executed. The producer dedicates specific lands in which it has both existing established reserves and the right to explore for and develop new reserves. The specified date of first delivery gives the producer time to find and develop reserves and install production facilities.

Direct Sale or Direct Purchase — Natural gas supply purchase arrangements transacted directly between producers or brokers and end-users at negotiated prices.

Displacement Volume — A direct purchase volume is a displacement volume when, assuming the absence of such direct purchase, the LDC could supply the account on a firm contract basis without itself contracting for additional firm volumes to accommodate the demand.

Distribution System — Generally, mains, service connections, and equipment that carry or control the supply of natural gas from interprovincial or interstate pipeline systems, or the point of local supply to individual end-users.

End-User — One who actually consumes or burns natural gas, as opposed to one who sells or resells it.

Established Reserves — Those reserves recoverable with current technology and under present and anticipated economic conditions. Includes reserves specifically proved by drilling, testing or production, plus that portion of contiguous recoverable reserves interpreted to exist with reasonable certainty based on geological, geophysical or similar information.

Evergreen Clause

A contract clause that extends the contract beyond the initial term, perhaps on a month-to-month or year-to-year basis, until one of the parties gives a required notice of termination. An evergreen clause makes a contract binding until one of the parties takes action to terminate it.

Federal Energy Regulatory Commission (FERC)

An agency in the United States which among other things, has jurisdiction over natural gas companies and producers that sell or transport gas in interstate commerce for resale. With respect to the natural gas industry, the general regulatory principles of the FERC are defined in the Natural Gas Act, the Natural Gas Policy Act and the Natural Gas Wellhead Decontrol Act. The FERC also has jurisdiction over wholesale interstate electric rates, hydroelectric licensing, and oil pipeline rates. The predecessor to the FERC was the Federal Power Commission.

Feedstock

Natural gas used as an essential component of a process for the production of a product. Natural gas may be required as a feedstock due to the chemical reaction involved, or because of the physical burning characteristics of natural gas compared with other fuels, such as temperature and by-products. Examples of feedstock use of natural gas include fertilizer manufacture, glass manufacture and while brick manufacture.

Fieldgate Price

The fieldgate is the point at which transfer of custody of gas, which has been gathered and undergone any processing to remove impurities and by-products, takes place from the producer to a buyer. More generally, fieldgate is used to specify a reference or delivery point on the production system. The term fieldgate price is used to refer to the price received for gas where producers are responsible for processing.

Firm Customer

A customer for whom contract demand is reserved and to whom the supplier is obligated to provide service.

Firm Service

Service offered to customers under schedules or contracts that anticipate no interruptions, regardless of class of service, except for force majeure.

Force Majeure Clause

A provision common in contracts that defines force majeure for purposes of the contract and specifies what effect force majeure will have on the rights and obligations of the parties under the contract. Typically, a force majeure clause provides that non-performance of an obligation of a party will be excused to the extent and for so long as performance is prevented by an event of force majeure. Force majeure provisions usually exclude obligations to pay money; require the party affected to give timely notice to the other party and to use reasonable diligence

to remedy the situation; and may reserve for either the party not affected by the force majeure, or both parties, the right to terminate or suspend the contract if the force majeure prevents performance for some specified period of time.

Franchise

A special privilege conferred by a government on an individual or corporation to occupy and use the public ways and streets for benefit to the public at large. Local distribution companies typically have exclusive franchises for utility service granted by provincial, state or local governments.

Gas Inventory Charge (GIC)

A charge paid by a buyer to its supplier for holding natural gas supplies ready to be delivered to the buyer. These charges may take at least two forms: (1) an "option" or "reservation" charge, in which a set fee is paid at the outset for each unit of deliver entitlement, and (2) a "deficiency" charge, in which the buyer pays after the fact a set fee for each unit natural gas not taken up to a pre-determined minimum or threshold quantity.

Gas Processing Plant

A facility in which raw natural gas from the wellhead is prepared for sale to final consumers by reducing or removing undesirable impurities and extracting commercially desirable non-methane hydrocarbons from the gas stream.

Gathering Lines

Pipelines that transport natural gas from individual wellheads to a compressor station, treating or processing plant, or main trunk transmission line.

Heating Value

The amount of heat produced by the complete combustion of a unit quantity of fuel. The gross, or higher, heating value is that which is obtained when all of the products of combustion are cooled to the temperature existing before combustion, the water vapour formed during combustion is condensed, and all the necessary corrections have been made. The net, or lower, heating value is obtained by subtracting the latent heat of vaporization of the water vapour formed by the combustion of the hydrogen in the fuel from the gross, or higher, heating value.

Industrial Sector

That portion of the natural gas market consisting of manufacturing, forestry and mining operations.

Interruptible Customer

A customer that receives service only at those times and to the extent that firm customers do not demand all of the available service.

Interruptible Service

Lower priority service offered to customers under rate schedules or contracts that anticipate and permit interruption on short

	notice, generally in peak-load seasons, by reasons of the claims of firm service customers and higher priority users.
Interruptible T-Service	An interruptible gas transportation service provided under contract for gas which is not owned by the pipeline company. The interruption is at the option of the pipeline company or distributor. There are two tiers of interruptible service. IS-1 is higher priority, offering less risk or interruption than IS-2, which is lower priority. The toll for IS-1 is higher than that for IS-2.
Interprovincial or Interstate Pipeline	A natural gas pipeline company that is engaged in the transportation of natural gas across provincial, state or international boundaries, and is subject to NEB or FERC jurisdiction.
Load Balancing	The balancing of gas supply to meet demand by using storage, other peak supply sources, curtailment of interruptible sales, or diversions from one delivery point to another.
Load Factor	The ratio of the average load over a designated period of time to the contracted maximum load, expressed in percent.
Local Distribution Company (LDC)	A company that obtains the major portion of its natural gas revenues from the operations of a retail gas distribution system and that operates no transmission system other than incidental connections within its own system or to the system of another company.
Market-Out	A provision in a natural gas sales agreement that allows one or both parties to demand renegotiation of the sales price and/or volumes of the contract. There are many forms of market out provisions with differing rights and effects.
Netback Price	The effective wellhead price to the producer of natural gas, based on the downstream market value for the natural gas less the charges for delivering the natural gas to market.
Nomination	A buyer's request for service under a service agreement.
Open Access	A basis for the provision of transportation services by inter-provincial, interstate and intra-provincial pipelines. The pipeline must provide service on a non-discriminatory basis to anyone requesting service at regulated rates.
Operating Demand Volumes	Volumes specified in a firm service contract less the volumes deemed to have been displaced by direct sales.

Premium — In the context of sales of natural gas, a price differential reflecting differences in the quality of the product or relationships, particularly for long-term firm commitments as opposed to spot sales.

Processing Plants — Facilities that process raw natural gas to extract desirable non-methane constituents. Processing plants may be owned by producers, independent processors, or transmission pipeline companies.

Rate Base — The value, established by a regulatory authority, upon which a utility is permitted to earn a specified rate of return. Generally, this value represents the amount of property used and useful in public service and may be based on fair value, prudent investment, reproduction cost, or original cost. The rate base may include a working capital allowance covering such elements as cash, working capital, materials and supplies, prepayments, minium bank balances and tax offsets. The rate base may be adjusted by deductions for accumulated provision for depreciation, contributions in aid of construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Reservation Fee — A set unit charge payable by the recipient of a service based on total entitlement. Similar to a "demand" charge.

Reserves Life Index — Remaining reserves divided by annual production.

Reserves to Production Ratio — Remaining reserves divided by annual production.

Residential Sector — That portion of the natural gas market consisting of private dwellings, including single and smaller multiple units, and larger residential units with individually metered apartments.

Sale for Resale — A sale of natural gas to a customer who will in turn resell the gas to someone else. A sale of natural gas other than to an end-user, e.g., a sale by a producer/marketer to a U.S. interstate pipeline that will in turn resell the natural gas to a local distribution company, or to a local distribution company that will in turn resell the natural gas to an end-user.

Self-Displacement — The purchase of gas by a buyer to displace gas it would otherwise obtain under its long-term contracts.

Shipper — An individual or company that contracts with a pipeline for transportation of natural gas. Normally, a shipper retains title to

	all natural gas delivered to the pipeline while it is being transported by the pipeline.
Spot Market	Commodity transactions in which the transaction commencement is near term (e.g., within 10 days) and the contract duration is relatively short (e.g., 30 days).
Spot Sale	Generally, an interruptible sale of gas under a 30-day contract.
Storage Facilities	Facilities used for the storage of natural gas. These are usually caverns carved out of natural salt domes or depleted natural gas reservoirs into which natural gas can be reinjected and produced with minimal loss.
Storage Service	A service in which natural gas is received by the seller of the service and held for the account of the customer for redelivery at a later time. Storage service usually requires the use of storage facilities, such as underground caverns in sale domes or depleted natural gas reservoirs that can be reinjected and produced with minimal loss. Storage services are typically utilized by customers to allow more even purchases or sales of natural gas throughout the year, despite variations in end-use demand. Storage service is also a critical element of the peak period deliverability or many interstate natural gas pipelines and distributors. Storage service may be separate from the transportation service necessary to deliver natural gas to and take natural gas from the storage facilities. Storage service usually requires payment of injection fees, withdrawal fees, and holding fees. Storage service also usually involves limits on rates and times of injection and withdrawal, and maximum volumes to be held.
Straddle Plant	A natural gas processing plant constructed near a transmission pipeline downstream from the fields where the natural gas in the pipeline has been produced. Generally, the straddle plant does not purchase and resell natural gas, but provides only a processing service for the owner of the natural gas or of processing rights to the natural gas. Frequently, natural gas producers reserve processing rights when the sell natural gas, so they can have valuable substances removed from the gas stream by a straddle plant.
Supply Aggregator	A supply aggregator purchases gas from several producers for the purpose of resale to a range of consumer interests (eg., Pan-Alberta Gas Ltd.).

Take-or-Pay Clause	A contract provision obligating the buyer to pay for a certain minimum quantity of product, whether or not the buyer actually takes than quantity during the stated period.
Thermal Generation	Energy conversion in which fuel is consumed to generate heat energy which is converted to mechanical energy and then to electricity in a generator. Normally, the fuel may be coal, oil, gas, or uranium (nuclear).
Transmission (Trunk) Lines	Pipelines transporting natural gas from principal supply areas to distribution centres, large volume customers or other transmission lines. Transmission lines generally have a linear configuration, may be quite large in diameter, operate at relatively high pressure, and traverse long distances.
Transportation Contract	A contract setting forth the terms and conditions applicable to transportation service.
Unbundled Service	The separation of pipeline services into discrete components (e.g., transportation, storage, gathering, sales, etc.). With unbundling, separate fees are charged for each service, based upon only the cost of providing that service.
Warranty Contract	A natural gas sales contract in which the seller commits to deliver a stated quantity of natural gas over a stated period to time, without limitation to or commitment of specific reserves or sources of natural gas, and generally with no production-related reservations.
Weighted Average Cost of Gas (WACOG)	The weighted average unit cost of a supply of natural gas WACOG is calculated as the total cost of all natural gas purchased during a period divided by either the total quantity purchased during the same period. This rate often serves as the basis upon which LDC system tariff rates are computed.
Wellhead Price	The wellhead is the equipment at the top of a well for maintaining control of the well. More generally, wellhead is used to specify a reference or delivery point on the production system. The term wellhead price is used to refer to the price received for gas by producers, net of any gathering or processing costs.